Wind Power Trading in Electricity Markets

A Thesis

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THESIS CERTIFICATE

This is to certify that the thesis titled **Wind Power Trading in Electricity Markets** submitted by Amit Mastud, to the Indian Institute of Technology, Madras, for the award of the dual degree, **Bachelor of Technology in Electrical Engineering and Master of Technology in Power system and Power electronics**, is a bonafide record of the research work done by him under our supervision. The contents of this thesis, in full or in parts, have not been submitted to any other Institute or University for the award of any degree or diploma.

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ABSTRACT

KEYWORDS: Congestion Surplus, Local Marginal Prices, Optimal Power Flow

Recently, the role of wind power as a tradable power is gaining importance in short term electricity market because wind power is the fastest growing renewable electricity generating technology. As wind power production is increasing rapidly and is pledged to form the substantial part of total production of electricity throughout the world in coming decade, it becomes important to consider the impact of wind power integration on power system reliability and its economics.

The aim is to facilitate small scale wind power integration into power system and test the societal benefits like lowering of bid in cost of production of the electricity market arising out of its integration. Most often wind power is price taker and treated as fixed input and is not included in optimal dispatch solution. But in the project work, impact of making the wind power as a part of security constrained economic dispatch solution of power system has been tested on simple three bus as well as 14 bus IEEE power system with Power World Simulator. The new optimal dispatch solution is important in deciding the market clearing price in congestion free power system as well as locational marginal prices (LMP) in congested power system so as to promote system reliability and security

A congestion method based on demand elasticity is used in the chapter to relieve the congestion in the power system. The effects of method are observed on LMPs of system for different amounts of wind power induction.

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ABBREVIATIONS

SO	System Operator
SC-ED	Security Constrained Economic Dispatch
SC-OPF	Security Constrained Optimal Power Flow
LMP	Local Marginal Pricing
MCP	Market Clearing Price
GWEC	Global Wind Energy Council
SC-UC	Security Constrained Unit Commitment

Chapter 1
Introduction

1.1 Project Motivation

The electricity sector is a major source of carbon dioxide emissions that contribute to global climate change. Over the past decade wind energy has steadily emerged as a potential source for large-scale, low carbon energy. Adoption of policy by several countries to reduce Greenhouse gas emissions has resulted in boosting the research and development on wind energy generation technology.

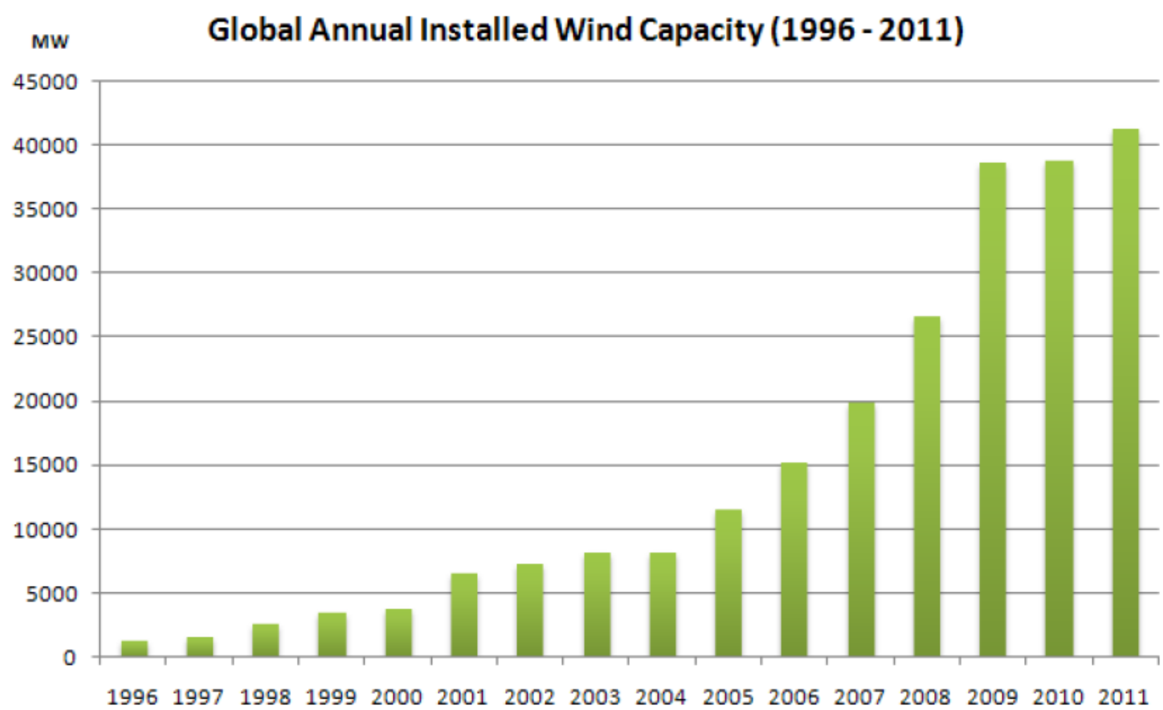

Fig. 1.1: Global Annual Installed Wind Capacity [Source: GWEC 2012]

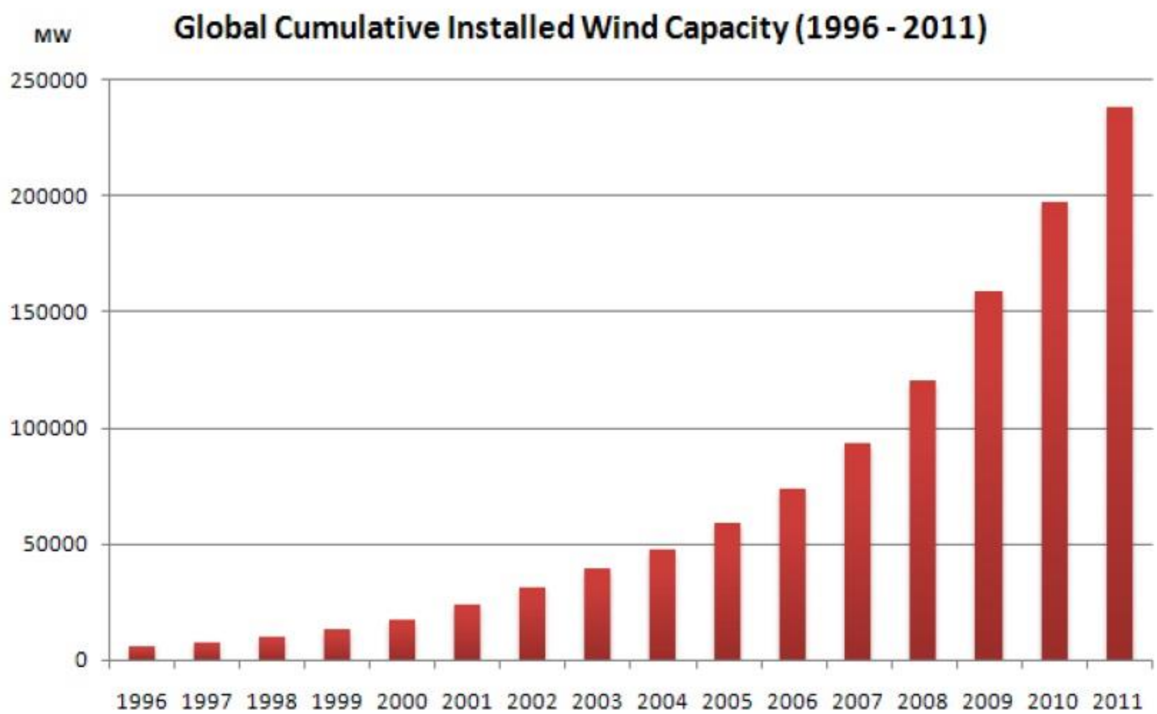

Fig. 1.2: Global Cumulative Installed Wind Capacity [Source: GWEC 2012]

This resulted in wind power becoming the fastest growing renewable electricity generating technology. Over the last decade, global wind power capacity has been growing at an average cumulative rate of over 30% which can be clearly observed in above two Fig 1.1 and 1.2 . Wind power stands out a major supplier of power among the alternative sources of energy. As wind power generation increases around the world, there is increasing interest in the impacts of adding wind power to the electricity grid.

However, there are certain issues with wind that must be considered while inducting it into power system. The two main issues are its variability and uncertainty. The wind is intermittent in nature. Sometimes wind blows; sometime it doesn't, adding difficulties to bid the wind power in the electricity market. Power system operators and researchers have been studying these impacts in wind integration studies as described in [1].The-state-of-the-art methods to study wind integration are described in [2]. Because of these integration issues, operators have traditionally treated wind power output in economic dispatch and commitment models and in energy markets as fixed inputs rather than control variables. This model treatment is most closely related to fixed (nonresponsive) load, which assumes an inelasticity of price. We refer to this model as the “price taker.” Since wind has an approximately zero variable cost as a free fuel source, this model has worked quite well in the past. This is because Independent System Operators (ISO) and Regional Transmission Organizations (RTO) who run least-cost dispatch would use as much wind power as possible unless the marginal cost of energy at the location of the wind power was below zero, which until recently has been a rare occurrence. In 2009, the New York Independent System Operator (NYISO) began a wind resource management program [3]. This program allowed wind plant owners to provide economic price offers into the real-time energy market, allowing system operators to dispatch the wind plants based on total economics of the system. The effect of small scale as well as large scale integration of wind power into power trading has to be understood by taking wind power as a part of optimal dispatch solution as well as fixed input.

The results and graphs were used to formulate the strategies for trading of wind power in electricity market as well as for concluding the need of wind power as part of dispatch solution in congested electricity market for relieving congestion to some extent and decreasing the cost of operation of power system. Finally the work focuses on effects of large scale integration of wind power on congested system operation in terms of congestion surplus, cost of operation, total surplus.

1.2.1 Objectives

The main objectives of this thesis are as follow:

1. To formulate the wind power trading strategy in electricity market for smoothening the induction of wind power into electricity market.
2. Understanding the effects of wind power induction on the LMPs and merchandising surplus of a small congested three bus system and benefits of wind power trading for reduction of generation costs of production.
3. Extending the wind power trading to large congested IEEE 14 bus system and observing the effects of small scale as well as large scale integration of wind power on system
4. Utilizing the knowledge gained from above three objectives to maximize the social welfare/ social surplus of economic operation of electricity market when wind is traded. Along with other conventional generators.

1.2.2 Scope

The systems which are used for simulations are assumed loss free, reactive power is not considered. The reactances of lines in test systems are assumed small. The congestion is considered only on one line in all the test systems. The congestion method used in the thesis. The project work is solely based from SO's point of view for maximizing the total surplus of power system taking into account system security and reliability.

1.3 Thesis Structure

Chapter 2 is dedicated to understanding various types of electricity market and different concepts used for power trading in electricity market. It focuses on the role of SO for ensuring stability, reliability and security of power system by different actions of SO like maintaining the balance of supply and demand, deciding on the supply and demand bids by various market players. It introduces the concept of Security Constrained Optimal Power Flow, LMPs, marginal cost of production and social surplus/Total surplus. The information is helpful in understanding why supply bidders bid at the marginal cost of production and mainly rest of the chapters in thesis.

Chapter 3 discusses the strategy for wind power trading to accommodate wind power easily in the competitive electricity market. It consists of formulations to show how MCP are calculated when we have supply and demand bids. A simple case study is used to understand the proposed strategy of wind power trading. Wind power is treated as a price taker in this chapter. The purpose of this chapter is to achieve the second objective stated in 1.2.1

Chapter 4 the effect of wind power when it is made part of OPF is observed. The wind power producer is no longer price taker here. It is used as a part SC-ED. The effects of using wind power as part of SC-OPF on the production cost as well as on system congestion surplus is tested with a simple three bus power system case study. The purpose of this chapter is to achieve the third objective stated in 1.2.1

Chapter 5 in this chapter, the results and conclusion derived from chapter 4 were tested on more complex system of 14 bus IEEE systems. A particular case of wind power trading at bus number 6 which is connected to a constrained line in the system is considered. The purpose of this chapter is to achieve the fourth objective stated in 1.2.1

Chapter 6 in this chapter a congestion method is devised to relieve the congestion in 14 bus system of chapter 5. The congestion management method is based on the concept of price elasticity of demand. The effects of wind power trading on congestion surplus and total surplus were tested on 14 Bus IEEE system. The purpose of this chapter is to achieve the final objective stated in 1.2.1 along with knowledge derived from all the previous chapters.

Chapter 2
Electricity Market Trading

2.1. Spot Electricity Market and Role of SO

Market is the place where buyers and sellers meet. Electricity is considered as a commodity that has to be traded. Since it is currently not economical to store large quantities of electrical energy, this energy must be produced at pretty much the same time as it is consumed. Since electrical energy delivered during one period is not the same commodity as electrical energy delivered during another period, the price will usually be different for each period. Electricity markets were monopolistic. Nowadays Electricity markets are deregulated, deregulation implies more competition.

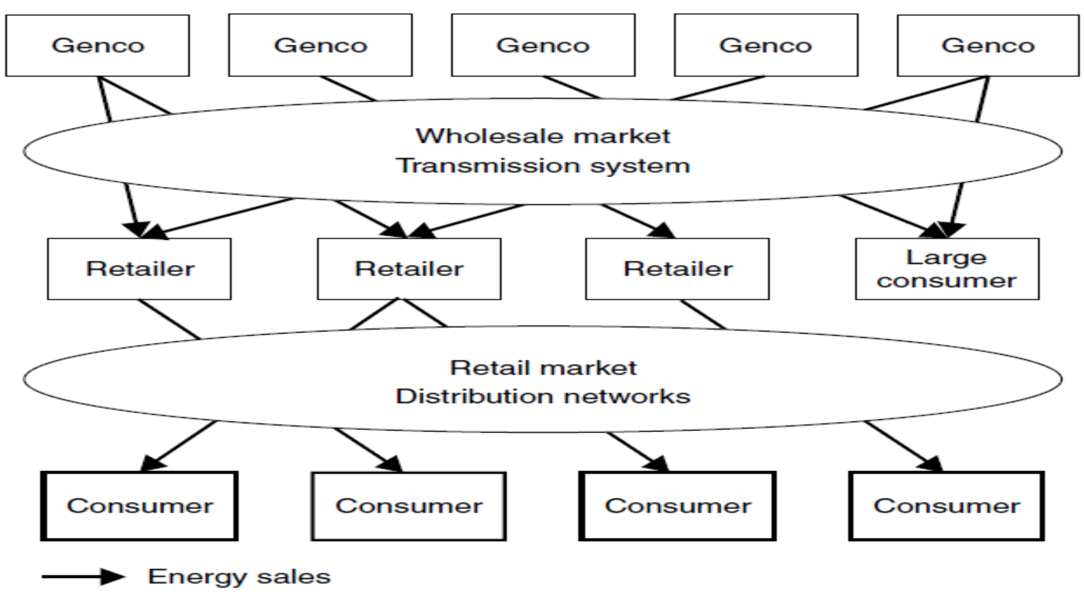

Fig. 2-1: Retail Competition Model of Electricity Market [4]

Figure 2.1 illustrates the ultimate form of competitive electricity market in which all consumers can choose their supplier. Because of the transaction costs, only the largest consumers choose to purchase energy directly on the wholesale market. Most small and medium consumers purchase it from retailers, who in turn buy it in the wholesale market. In this model, the "wires" activities of the distribution companies are normally separated from their retail activities because they no longer have a local monopoly for the supply of electrical energy in the area covered by their network. In this model, the only remaining monopoly functions are thus the provision and operation of the transmission and distribution networks.

In a spot market, the seller delivers the goods immediately and the buyer pays for them “on the spot”. No conditions are attached to the delivery. This means that neither party can back out of the deal. A spot market has the advantage of immediacy. As a producer, I can sell exactly the amount that I have available. As a consumer, I can purchase exactly the amount I need. Unfortunately, prices in a spot market tend to change quickly. A sudden increase in demand (or a drop in production) sends the price soaring because the stock of goods available for immediate delivery may be limited. For every commodity, imbalances almost always arise between the amounts that a party has contracted to buy or sell and the amount that it actually needs or can produce. Spot markets provide a mechanism for handling these imbalances. If electrical energy is to be treated as a commodity, a spot market must therefore be organized. The system operator (SO) is given the responsibility to maintain the system in balance using what one might call a “managed spot market”. This mechanism is a market because the energy that is used to achieve this balance is freely offered by the participants at a price of their own choosing. It is a spot market because it determines the price at which imbalances are settled. However, it is a managed market because the bids and offers are selected by a third party (the SO) rather than through bilateral deals. Role of SO is described in below Figure 2.2.

From the Figure 2.2, we can see, the producers and the consumers must inform the SO of their contractual positions, that is, how much power they intend to produce or consume during the period under consideration. The SO combines that information with its own forecast of the total load to determine by how much the system is likely to be in imbalance. The SO must then decide which balancing bids and offers it will use to cover the imbalances.

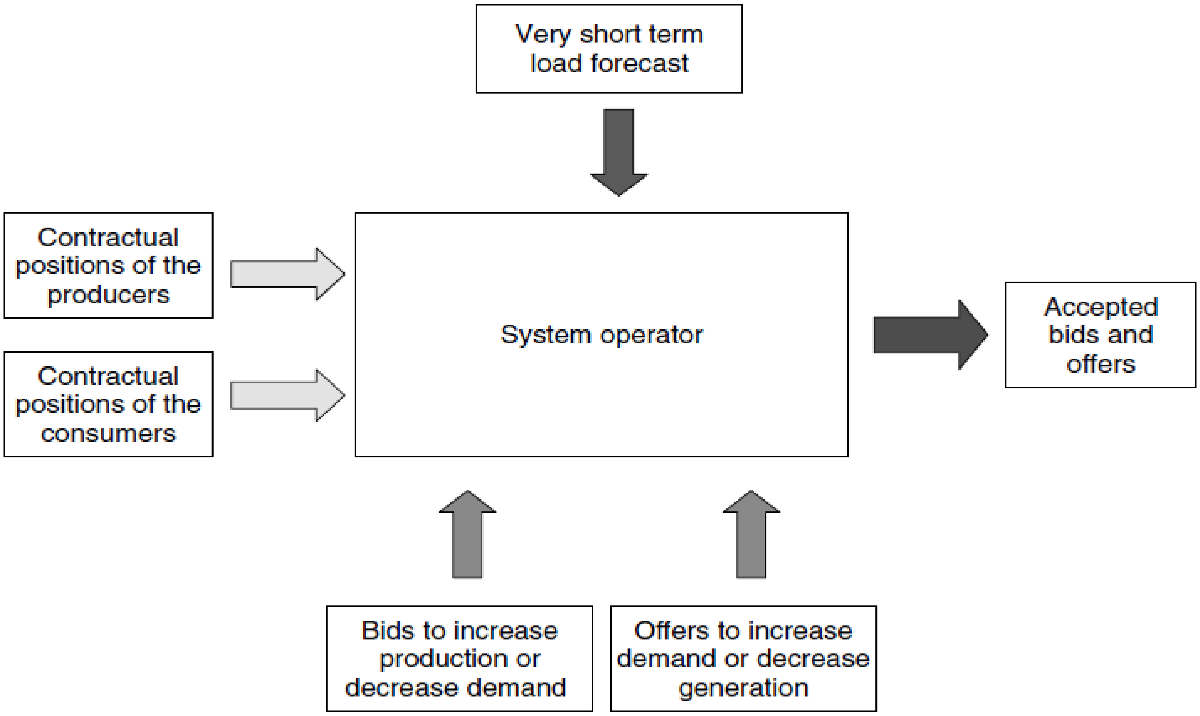

Fig. 2.2: Schematic diagram of the operation of a managed spot market for electricity [4]

2.2. Marginal Cost of Production

Marginal cost of production in electricity production is the cost of producing extra megawatt of power. In order to maximize the profits, generating unit has to produce at lesser cost and sell at higher price so that difference between revenue derived out of selling electricity and cost of cost producing gets maximized. Let's take generating unit called unit *i*. For the sake of simplicity, we will consider a period one hour and we will assume that all quantities remain constant during that period. The maximization of the profit from this unit during this hour can be expressed as the difference between the revenue resulting from the sale of the energy it produces and the cost of producing this energy:

$$\max \Omega_i = \max[\pi \,.\, \mathrm{P}_i - C_i \,.\, \mathrm{P}_i] \qquad (2.1)$$

where *Pi* is the power produced by unit *i* during that hour, π is the price at which this energy is sold and *Ci(Pi)* is the cost of producing this energy. If we assume that the only variable over which the company has direct control is the power produced by this unit, the necessary condition for optimality corresponding to above equation is

$$\frac{\mathrm{d}\Omega_i}{\mathrm{dP}_i} = \frac{\mathrm{d}(\pi\,.\,\mathrm{P}_i)}{\mathrm{dP}_i} - \frac{\mathrm{d}C_i(\mathrm{P}_i)}{\mathrm{dP}_i} = 0 \qquad (2.2)$$

The first term in this expression represents the marginal revenue of unit *i*, that is, the revenue the company would get for producing an extra megawatt during this hour. The second term represents the cost of producing this extra megawatt, that is, the marginal cost. So in order to maximize the profits the generating unit i must produce the electricity such that marginal cost of its production should just match the marginal revenue. But as we will marginal revenue turns out to be market price

$$MR_i = MC_i \qquad (2.3)$$

If the competition is perfect (or if the potential output of the unit is very small compared to the size of the market), the price π is not affected by changes in Pi. The marginal revenue of unit *i* is thus

$$MR_i = \frac{\mathrm{d}(\pi\,.\,\mathrm{P}_i)}{\mathrm{dP}_i} = \pi \qquad (2.4)$$

which expresses the fact that a price-taking generator collects the market price for each megawatt-hour that it sells. Under these conditions, if the marginal cost is a monotonically increasing function of the power produced, the generating unit should increase its output up to the point at which the marginal cost of production is equal to the market price:

$$\frac{\mathrm{d}C_i(\mathrm{P}_i)}{\mathrm{dP}_i} = \pi \qquad (2.5)$$

The marginal cost includes the costs of fuel, maintenance and all other items that vary with the power produced by the unit. Costs that are not a function of the amount of power produced in the period under consideration (e.g. the amortized cost of building the plant or the fixed maintenance and personnel costs) are not factored in the marginal cost and are thus irrelevant when making short-term production decisions.

As long as competition is perfect, the output of each generating unit should be determined using Equation 2.4. Since the price is considered as given, this implies that all generating units can be dispatched independently, even if a generating company owns more than one unit.

2.3.1 Centralized Trading Over Constrained Transmission Network

In a centralized or pool-based trading system, producers and consumers submit their bids and offers to the system operator (SO), who also acts as market operator. The SO, which must be independent from all the other parties, selects the bids and offers that optimally clear the market while respecting the security constraints imposed by the transmission network. Transmission lines used in power system have their upper limit on how much power should be transferred through lines. As part of this process, the system operator also determines the market clearing prices. If we don't have losses and congestion in transmission network, then SO can come up with a single Market clearing price for all market which can be binding for all the producers and consumers. In other words, all consumers across the market will buy electricity at that single MCP and all producers will sell electricity at the same price.

2.3.2 Locational Marginal Pricing (LMP)

Constraints imposed by the need to maintain the security of the system can thus create congestion in the transmission network. This congestion divides what should be a single market into separate markets. Because of the congestion, an additional megawatt of load in each country would have to be provided solely by the local generators. The marginal cost of producing electrical energy is therefore different in each country. If these separate markets are still sufficiently competitive, the prices are still equal to the marginal costs. We thus have what is called locational marginal pricing because the marginal cost depends on the location where the energy is produced or consumed.

When losses or congestion in the transmission network is taken into account, the price of electrical energy depends on the bus in which the power is injected or extracted. The price that consumers and producers pay or are paid is the same for all participants connected to the same bus. If a different price is defined at each bus or node in the system, locational marginal pricing is called nodal pricing. Locational marginal prices are higher in areas that normally import power and lower in areas that export power. Throughout the project, transmission network is assumed lossless. So the only factor which contributes to the LMPs is the capacity constraints on transmission line, which has been considered in the project.

If there are m transmission constraints in the system then there are m+1 marginal generator. Each of these marginal generators set the price where they are connected and they also determine the price at other buses. These generators are also known as partly loaded.

2.3.3 Merchandizing surplus

It arises out of congestion or losses in the network. In congestion free network also merchandising surplus exists owing to transmission line losses. All the systems considered in project are lossless. So merchandising surplus calculated in the project is owing to transmission constraints in the network. In that case, merchandising surplus is the difference between consumer payments and producer revenues.

So when is cleared with single market price by SO, then merchandizing surplus is zero. This is due to demand of power is equal to supply of power and price of buying and selling electricity is same at all buses in the network. Merchandising surplus is positive or negative when market has LMPs due to congestion. This surplus is also called as Congestion Surplus

2.4 PowerWorld Simulator and Security Constrained-OPF

During the project power world simulator was used extensively. PowerWorld Simulator is an interactive power system simulation package designed to simulate high voltage power system operation on a time frame ranging from several minutes to several days. The software contains a highly effective power flow analysis package capable of efficiently solving systems with up to 60,000 buses. Simulator also offers five optional product add-ons to meet your needs.

- Optimal Power Flow (OPF)
- Available Transfer Capability (ATC)
- Power-Voltage Reactive Power-Voltage Tool (PVQV)
- Automation Server (SimAuto)
- Security Constrained Optimal Power Flow (SCOPF)

In the project, Optimal Power Flow (OPF) has been used. The OPF determines the optimal dispatch, subject to transmission constraints. Optimal usually means least cost (or most economical), but may also mean minimum control change. This is the objective function and may be set on Simulator's OPF Options and Results dialog. This functionality is sometimes also described in literature as Security-Constrained Economic Dispatch or SCED. There are two OPF Solution methods.

- Non-linear approach using Newton’s method
- Linear Programming (LP)

Non-linear approach using Newton’s method handles marginal losses well, but is relatively slow and has problems determining binding constraints while the Linear Programming (LP) –OPF solution method is fast and efficient in determining binding constraints, but has difficulty with marginal losses. As in the project, transmission network is assumed to be lossless. The Linear Programming (LP) –OPF solution method is used in all the test cases. It is also known as Primal LP OPF Solution method.

Chapter 3

Wind Power Trading in Unconstrained Transmission Network

3.1 Introduction

This chapter describes the way in which wind power has to be traded in the electricity market to facilitate its integration into existing market. The market is assumed to be congestion free and lossless. This leads to having single market clearing price for all the participants in the market. A case study has been discussed to understand the same. The necessary formulation and theory for case study has been discussed before case study.

3.2 Wind Power Trading and Its Problems

Wind is an innovative, clean, modular, and intermittent technology. It is capital-intensive but has low operating costs. Wind turbines have become more efficient, and their costs have dropped. Wind farms are becoming an increasingly offshore and onshore site. Though wind power offers many possible benefits, it faces a number of potential barriers to participate competitively in the current restructured electric industry [8],[9],[11]. The type and severity of these barriers will depend upon the final design and implementation details of public policies and regulatory reforms that are chosen for the new electricity industry. Their large-scale integration in the electricity system presents some planning and operational difficulties mainly due to the intermittent and difficult-to-predict nature of wind that is considered as unreliable energy sources [12],[13]. However, the percentage of the energy produced by wind is increasing due to technology and efficiency improvements, government financial supports, and energy policies.

The chapter deals with pricing mechanism for wind power sustainability into the electricity market and compare the economic and dispatch aspects with other available options. The effectiveness of the proposed pricing mechanism is tested on supply-side bidding scenario in the linear bidding market model. Suitable mathematical models are developed for the calculation of market clearing price (MCP). It has been established with different case studies that the MCP calculated without wind power is a better option. In the event of wind power availability, dispatching generators should reduce their outputs to accommodate the wind power in the energy market. The impact of the wind power for mitigating market power and for providing ancillary services has also been discussed.

3.2.1 Technical Challenges on Wind Power

The site of wind power depends on the availability of wind throughout the year. The intermittent nature of wind is a real challenge in the system operation. This problem becomes more severe in the restructured electricity market.

Forecasting Errors: The impacts of wind's variability on system operating costs are not negligible [12]. In most of the cases, the costs are less than 10% of wholesale energy value and in some cases, it is substantially less. The assessment of cost associated with wind generation prediction errors in an electricity market is presented in [9] an efficient wind forecasting tool is still necessary to avoid the forecasting error.

System Operational Difficulties: Several thorough investigations of wind's impacts on power system operation and operating cost have been carried out. Most of the studies have been done for the vertically integrated electric power system. Small amount of wind energy may not have severe impact on the power system operation and control; however, with a large penetration of wind energy, system operation is one of the major challenges. Several studies have been carried out to see the impact of wind energy integration into the grid. The impact depends on the location of wind energy, system size, network configuration, etc.

3.2.2 Financial challenges

All the technical concerns lead to a financial challenge in the electricity market. In a bundled power system, the financial risk is less compared to the unbundled power system. Two types of studies are normally done: cost-based and market-based. A very important distinction exists between these studies. In cost-based studies, operating cost is estimated with and without the effect of wind variability. In contrast, market-based study includes the conventional costs attributable to the wind's variability, the costs of the wind energy, etc. Wind energy generators are treated as the conventional generators and are paid according to the hourly market price.

Due to technical difficulties of wind power to generate electricity without wind, which is a natural phenomenon, it may not be competitive compared to the conventional power generators. The cost of wind power without government subsidy is also a barrier in profitable trading in the market. On the other hand, market operator can use wind power for the welfare of customers and can make the wind power financially viable. The options include market power mitigation, ancillary service provisions, market collusion with pump storage or hydro power plants, etc. The following sections describe the market clearing mechanism that will be used to see the impact of the wind power bidding in electricity market.

3.3.1 Linear Bid Market

If bidding is done only by the suppliers, it is termed as a single-sided bidding. The bidders can be allowed to bid their outputs or demands either in the blocks or as a linear form, as shown in below Fig.3.1

Single Sided Bidding: In a linear bid market, a supply curve that is a function of the market price (*p*) of any bidder *i* can be expressed as

$$q_i(p) = \frac{p}{m_{si}} \tag{3.1}$$

Where,

m_{si} = slope of supply curve ($\$/MW^2h$)

p = market price of any bidder ($\$/MWh$)

q_i(p) = quantity of power (MW)

Combined Supply curve/cumulative supply curve will be

$$q(p) = p\sum_{i=1}^{N_g} \frac{1}{m_{si}} \tag{3.2}$$

Where,

N_g= Number of supply generators who bid into market

If the electricity demand in the market is fixed then market clearing price will be obtained by following equation

$$p^* \sum_{i=1}^{N_g} \frac{1}{m_{si}} = D \qquad (3.3)$$

Where,

p^* = market clearing price ($\$/MWh$)

D = fixed demand of electricity in market (MW)

Double Side Bid market : If both suppliers and customers are allowed to bid into the market, it is known as a double-sided bidding mechanism. Here demand is not constant and depends upon the bids placed by consumers. The demand curve for any consumer or load in linear bid model is given by

$$d_i(p) = \frac{p_{io} - p}{m_{di}} \qquad (3.4)$$

Where,

$d_{i(p)}$= demand of electricity by consumers, unit-(MW)

m_{di} = slope of demand curve, unit-($/MW^2h$)

p = price variable, of which demand curve is a function of, unit- ($\$/MWh$)

p_{io} = curve intercepts the y axis of price at p_{io} ,unit-($\$/MWh$)

The combined demand curve will be

$$d_i(p) = \sum_{i=1}^{N_d} \frac{p_{io}}{m_{di}} - p \sum_{i=1}^{N_d} \frac{1}{m_{di}} \qquad (3.5)$$

Where,

N_d = number of demand bidders in the market

The market clearing price p^* can be calculated by

$$p^* \sum_{i=1}^{N_g} \frac{1}{m_{si}} = \sum_{i=1}^{N_d} \frac{p_{io}}{m_{di}} - p \sum_{i=1}^{N_d} \frac{1}{m_{di}} \tag{3.6}$$

3.3.2 Market Clearing Price with Wind Generators

Wind power is intermittent and unpredictable in nature. Sometimes wind blows, sometimes it doesn't. It's mandatory and biding to supply electricity in the electricity pool, once the bid has been placed by supplier. If the wind power is unavailable then it has to pay the imbalance penalties. The SO buys the same amount of power from some other supplier. That is why, Wind power generators generally don't bid into market. Wind power is taken into market as and when available. There arise two options of deriving MCP

- Option A: Not considering Wind Input while calculating MCP
- Option B: Considering Wind Input while calculating the MCP

The linear bid model is used to calculate MCP for both above option for two cases.
Case A: Linear supply bid with fixed demand
Case B: Linear supply bid with linear demand bid

Table 3.1 shows linear bidding parameters, at any unit time, of three supply bidders, as defined in (3.1). The lower and upper limits of these generators are also given in Table 3.1. The cumulative supply curve obtained by using (3.2) is shown in Fig. 3.1. The case B has not been discussed as it is nearby same as that of case A.

3.4 Case Study: Linear supply bid with fixed demand

In this case a constant demand of 100 MW is considered. If wind power is not available; the total demand will be met by the three supply bidders 1, 2, and 3. The MCP, which is the intersection of the demand curve and the cumulative supply curve, is 5.26 \$/MWh. The scheduled output powers of the supply bidders is obtained by an intersection line parallel to X- axis with value of 5.26 \$/MWh and the individual supply bid lines, as shown in Fig. 3.1. The bidders 1, 2, and 3 will generate 52.63, 21.05, and 26.32 MW, respectively

Table 3.1: Suppliers Linear Bid Data

	m_{si} ($\$/MW^2h$)	$q_{min}(MW)$	$q_{max}(MW)$
Gen-1	0.10	0	100
Gen-2	0.25	0	50
Gen-3	0.20	0	100

Consider that the wind power is available. Now, it must be absorbed without knowing its actual price of output. With the availability of the wind power (Pw) megawatts, the supply bidders can share the remaining load (100 $-Pw$) MW to dispatch. The MCP can be obtained as

$$p^* = \frac{100 - P_w}{\sum_{i=1}^{N_g} \frac{1}{m_{si}}} \tag{3.7}$$

For 5 MW of wind power, the corresponding MCP is now \$5.0/MWh. Since the MCP is reduced, it may not be possible to recover the cost of the wind power and also the excess cost during the no availability of the wind power. Thus, the market price is to be fixed to the value obtained without considering the wind generation that is \$5.26/MWh. The output of bidders will be reduced according to the bidding characteristics that can be obtained by reducing the output by (Δqi), given as

$$\Delta qi = \frac{P_w}{m_{si} \sum_{i=1}^{N_g} \frac{1}{m_{sj}}} \tag{3.8}$$

New output of bidders will be $$q_{inew} = q_i - \Delta qi \tag{3.9}$$

3.5 Case Study: Results

Table 3.2: Output Powers and Payments

	Output MW		Payments Received ($/h)		Strategy Payment($/h)
	Without Wind	With Wind	Without Wind	With Wind	
Gen-1	52.63	50	277.01	250	263.16
Gen-2	21.05	20	110.80	100	105.26
Gen-3	26.32	25	138.51	125	131.58
WindPower	0.00	5	0	25	26.32
Total	100	100	526.32	500	526.32

Table 3.2 has the new values of supply amount of generators when 5 MW of wind power is inducted into system. These new values are calculated by equation number (3.9).

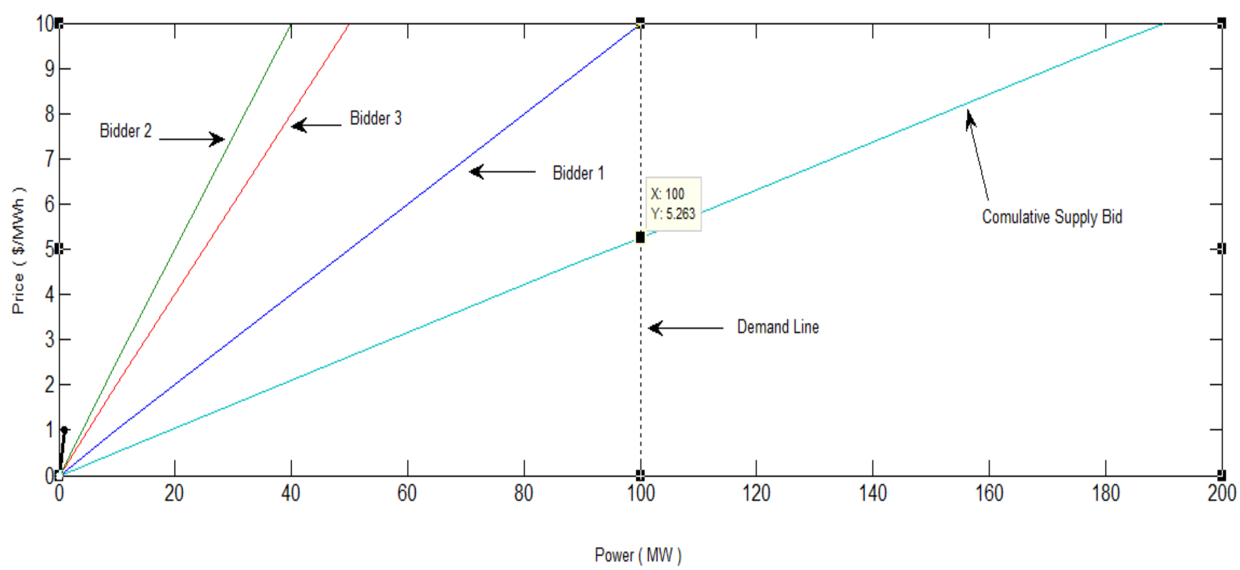

Fig. 3.1: Supply Curves and Constant demand

Fig 3.1 shows the cumulative supply curve of all supply functions of bidders intersecting the constant demand of 100 MW. The market clearing price is 5.2632 $/MWh.

3.6 Case Study: Strategy for Wind Power Trading

1. Keep the MCP of 5.26 $/MWh as the price at which generators will receive the payments for their output power in both the cases of with and without wind power
2. If wind power is not available we can ask generators to produce 5 MW more (as shown in column 1,table 3.2) and meet the unavailability of wind power
3. If we have wind power then also generators are getting 5.26 $/MWh as a MCP even when they are willing to provide power at 5 $/MWh
4. So no generator will face loss and wind power is also getting fare price of 5.26 $/MWh
5. System Operator (SO) does not have deficiency of money to give generators when wind is suddenly unavailable

3.7 Summary

A suitable trading strategy has been proposed for wind power trading. But the case study does not take into account the factor of constraints on transmission network in the market which gives rise to LMPs. Next chapter deals with this issue and proposes a new method

Chapter 4

Wind Power Trading In Congested Three Bus System

4.1 Introduction

In the last chapter, we saw the role of wind power as an incompetent market player. In this chapter, the effect of wind power when it is made part of OPF is observed. The wind power producer is no longer price taker here. It is used as a part SC-ED. The effects of using wind power as part of SC-OPF on the production cost as well as on system congestion surplus is tested with a simple three bus power system case study.

4.2 Benefits of Wind's Participation in SC-ED and Energy Markets

If there are m transmission constraints in the network then there are m+1 marginal generators which set the prices (LMPs) at the buses where they are connected and at the same time decides the prices at other buses in the network. Security-constrained economic dispatch (SCED) and security-constrained unit commitment (SCUC) determine the least cost solution to meet the demand subject to constraints, and they determine the LMP.

As wind generation entered energy markets, system operators were often uncomfortable using it for SCED/SCUC to relieve transmission congestion and follow demand. Therefore, wind was treated as a fixed resource, often referred to as a negative load or price taker. This is similar to how self-scheduled resources that do not participate in the energy market and non-responsive loads are treated. At low penetrations, with sufficient transmission capacities, it is rare that the SCED/SCUC would ever create a solution other than to use the maximum wind power available since wind has essentially zero variable costs. However, with higher penetrations and congested transmission networks, this may not be true.

Wind is treated as a price taker. Given a system with large wind power penetration and limited transmission, the LMP for a location with wind power is negative due to a transmission constraint, i.e., any generator in that location must pay to generate. LMP is mathematically calculated as the dual variable (shadow price) of the nodal power balance constraint. Since the constraint is an equality constraint, it is possible for this shadow price to be negative. It may be possible that the wind generator is settling in the energy market (even if not participating in the market solution) and now must pay the market to generate. The likelihood in this scenario is that the system operator asks the expensive generation on the other side of the transmission constraint to produce counter-congestion. This increases the total system production costs, increases the load's LMP, and harms the financial situation of the wind generator who must pay the system operator while the wind generator is generating energy. Now consider the other extreme. Though the system operator does not have the wind as part of its dispatch solution, the wind plant is quite capable of reducing its power output. When it is being financially harmed to produce power, the wind plant has an incentive to reduce output. Perhaps due to an extreme case of negative prices, the wind plant now ceases power production from the entire plant. If the wind plant was producing significant power before ceasing its production, this would have an effect similar to a loss of a large conventional generating unit. This causes a number of reliability issues, including a decline in system frequency, violation of transmission flow limits, and voltage instability. This is undesirable for system operators.

Here, the key issue is that the wind owner/operator did not know how to contribute to reducing the transmission congestion.

The SCED/SCUC is a typical optimization problem. It maximizes the social welfare (which in the case of inelastic demand is the same as minimizing the total bid production costs), while it is subject to a series of constraints. These constraints may include generating unit-specific constraints, system-wide demand and operating reserve constraints, transmission constraints, and contingency constraints [14]. By definition, whenever a constraint is added to a maximization optimization problem, the objective value will be less than or equal to the objective value without the constraint (for a minimization problem, the objective value will be greater than or equal to the objective value without the constraint). This means that the SCED/SCUC can only decrease the social welfare or increase the total bid production cost when a constraint is added. When wind is considered a price taker, it adds a constraint so that the output must be equal to the scheduled value (usually from a wind forecast or market participant bid). Allowing wind to be on dispatch will eliminate the downward constraint resulting in reduced system costs.

The end result is that allowing wind generators to participate as flexible generators in LMP-based energy markets improve reliability and efficiency. It ensures that the dispatch direction are made by the dispatch software rather than off-line by operators or by the owner/operator of the plant. The dispatch is visible to operators and they can still make decisions for reliability purposes, but they do not make as many “out of market” decisions that may not be as efficient. This also creates more efficient pricing that better matches the system conditions. Essentially, this allows wind generators to behave in a similar manner to conventional generators with the key difference that their unconstrained maximum generation limit depends on wind availability at all instances. But for this exception, wind generators are far less constrained than conventional generation. They have no minimum generation limits, no minimum up times, and, usually, fairly high ramp rates. The next section shows numerical simulations that highlight the benefits.

4.3 Case Study: Simple Three Bus System

The numerous power system constraints that system operators must incorporate can have a large influence on the scheduling solution. Transmission constraints can cause localized issues that may require re-dispatch. Commitment constraints of generating units may require options of scheduling with more flexible resources. Therefore, we will provide two examples.

- Option I: Taking wind power a pure price taker
- Option II: Taking wind power part of SC-ED

To understand how transmission constraints impact results, the first case study is a single time point SCED. Obviously, the results can vary system by system depending on what constraints are used in the scheduling solution and which generating units and transmission topology make up each system. But we can generalize the findings of this case study. Case study simulations are carried out in PowerWorld Simulator 17.0 using the Add on Primal- LP OPF provided in it. All simulations are carried out using a Primal LP-OPF, minimizing the bid production cost, with the load balance constraint, generation maximum capacity constraints, and the transmission constraints using a linear dc power flow approximation. Note that due to the small system size, line outage contingencies are not considered in these simulations.

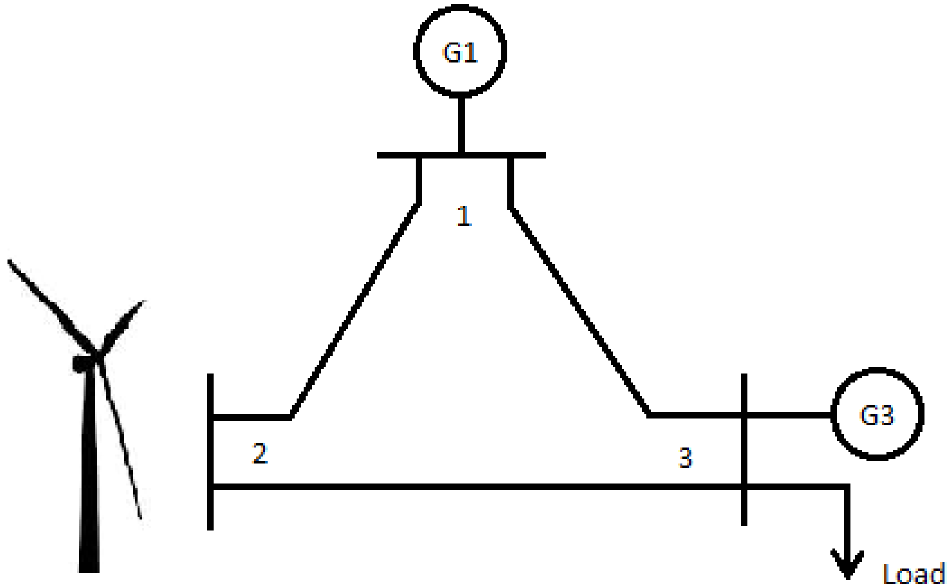

Fig. 4.1: Single Line diagram of three bus system [5]

Table 4.1: Generator Bid data, Load data, Line reactance and Capacity Flow [5]

G1= 250 MW	Wind Forecast	G3 = 100 MW	Load = 250 MW	L2-3 Limit =100 MW
10 $/MWh	100 MW	50 $/MWh	X12=X13=X23	

A cheap conventional generator is located at bus 1 (G1), an expensive conventional generator at bus 3 (G3), and a wind plant is located at bus 2 (WIND). The load is all located at bus 3. There is a thermal transmission limit of 100 MW on line L2-3. Generating capacities, bid production costs, and the load level are shown in Fig. 4.1. The reactances of all lines are equal.

4.4 Simulation Results

Option I: Taking wind power a pure price taker

As you can see in the Table 4.2, the total cost of production when wind was used as price taker in a congested network is 3500 $/h .The wind has got the LMP of -30 $/h, forcing it to pay the price to buyers to remain in the market.

Table 4.2: Wind Power- as a Price Taker

	Power (MW)	LMP($/MWh)	Supply Bid($/MWh)	Cost of Production($/h)
Generator-1	100	10	10	1000
Wind Gen-2	100	-30	-	-
Generator-3	50	50	50	2500
Total	250		500	3500

Option II: Taking wind power- part of SC-ED

When wind participates in the optimal dispatch solution, the price at which it bids is set at 0 $/h. As you can see in the Table 4.3, the LMPs at different buses have been changed compared to the Option I. Total cost of production is now 2000 $/h.

Table 4.3: Wind Power- part of optimal dispatch solution

	Power (MW)	LMP($/MWh)	Supply Bid($/MWh)	Cost of Production($/h)
Generator-1	200	10	10	2000
Wind Gen-2	50	0	0	-
Generator-3	0	20	50	0
Total	250		2000	2000

Option I:

As we see in the Table 4.4,

Congestion Surplus = Consumer Payments -Generation Revenues

Congestion Surplus = 12500-500 = 12000 $/h

Table 4.4: Wind Power- a fixed schedule

Bus No.	Load	LMP ($/MWh)	Generation (MW)	Generation Revenue($/h)	Consumer Payments($/h)
1	0	10	100	1000	0
2	0	-30	100	-3000	0
3	250	50	50	2500	12500
Total	250			500	12500

Option II: As we see in the Table 4.5,

Congestion Surplus = Consumer Payments -Generation Revenues

Congestion Surplus = 5000-2000 = 3000 $/h

Table 4.5: Wind Power- Part of SC-ED

Bus No.	Load	LMP ($/MWh)	Generation (MW)	Generation Revenue($/h)	Consumer Payments($/h)
1	0	10	200	2000	0
2	0	0	50	0	0
3	250	20	0	0	5000
Total	250			2000	5000

4.5.1 Observations

1. The cost of production of generation in Option I was 3500 $/h and it has been brought down to 2000 $/h in Option II. This is a 40 % reduction in cost of production.
2. Also the Congestion Surplus was brought down from whooping 12000 $/h in Option I to a mere 3000 $/h in Option II. The congestion surplus of the system was reduced by 75%.
3. Generation revenue increased from 500 $/h to 2000 $/h. The LMP at load bus 3 was brought down from 50 $/MWh to 20 $/MWh by 30 $/MWh due to more efficient supply of energy

4.5.2 Summary

Thus using wind power as part of OPF by SO decreases the cost of production. Allowing wind power and other intermittent resources to participate in LMP-based energy markets and SCED/SCUC solutions improves efficiency by giving more options to reduce transmission congestion.

Since G3 originally received an LMP equal to its bid production cost, and theoretically received no profit in the case of wind as a price taker, no market participant is adversely affected when the wind power plant is allowed to participate in the LMP energy market and in the SCED. This can be seen as bus 3 got new LMP of 20 $/MWh

Economic wellbeing of any business transaction demands the increase in social surplus or total surplus, which is nothing but the difference of consumer payments and producer's cost of production. Here social surplus increases with decrease in cost of production and increase in consumer payments.

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Chapter 5

Wind Power Trading In Congested 14 Bus IEEE System

5.1 Introduction

The source of data for 14 bus IEEE system is given in [15]. The generator data of have been modified and is given in chapter.

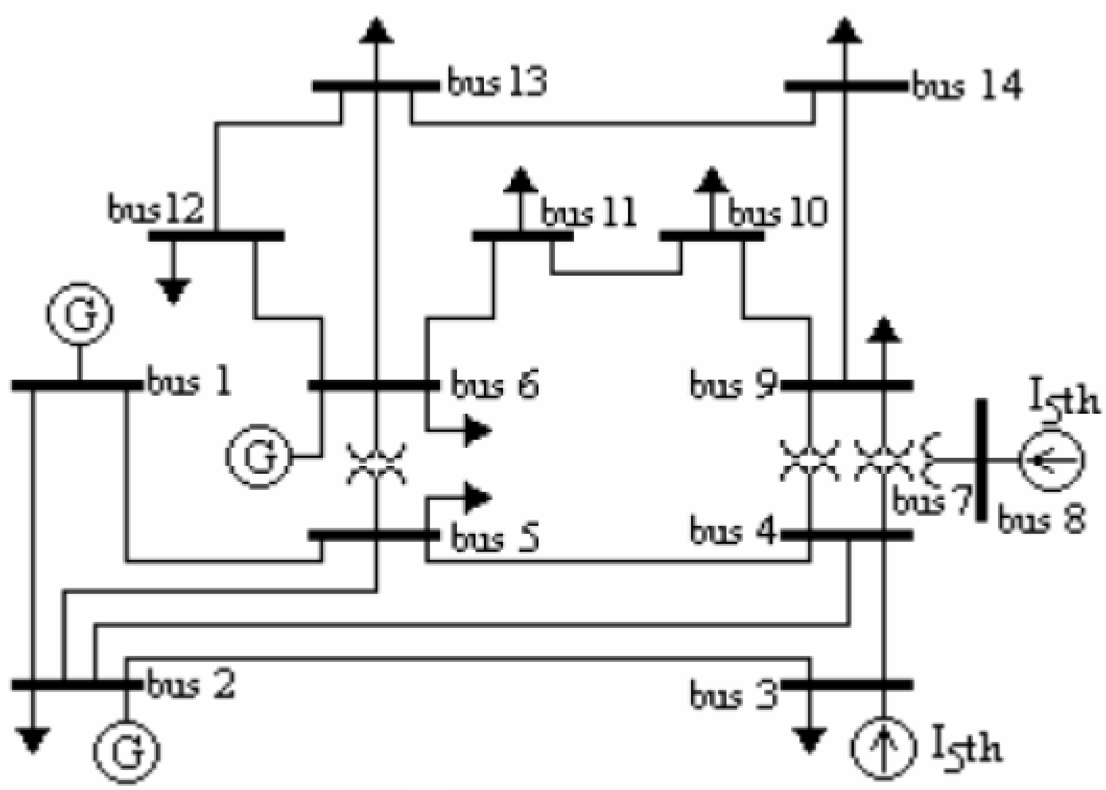

Fig. 5.1: IEEE 14 Bus System [6]

In Part I of this chapter at the beginning, the test system is simulated by PowerWorld 17.0 to calculate the MCP for data given in [15] without considering wind power for trading. Then SC-ED was performed using Primal LP-OPF on system without considering wind power to calculate LMPs. The LMPs and single MCP are plotted against the 14 nodes in the system.

Then in Part II, Wind power is considered for trading. Here Wind is treated as fixed schedule as well as taken as part of SC-ED. Results were obtained for variation in LMPs and congestion surplus due to presence of wind power on bus 6 and 13 which are connected to constrained line. Similar to the Part I, simulations were carried out by PowerWorld Simulator.

5.2.1 Part- I: Simulation Results

The generator data given in [15] for IEEE 14 bus system was modified and replaced with generation supply curve data given in Table 5.1. The data was obtained from [6]

Table 5.1: Generator Parameters

Generator	c_{2i}	c_{1i}	c_{0i}	P_{max}	P_{min}
1	0.04303	20	0	332.4	0
2	0.25	20	0	140	0
3	0.01	40	0	100	0
6	0.01	40	0	100	0

5.2.2 Assumptions

As we are dealing with real power market, the reactive power constraints are ignored and some assumptions are made. These are

1. The angle difference between each node is small
2. The voltage profile is flat.
3. Line resistance is small enough to be neglected

The data was simulated with Primal LP-OPF add on in PowerWorld Simulator for SC-ED. DC approximation was used along with Primal LP-OPF solution method. Below is the plotted graph of simulation result.

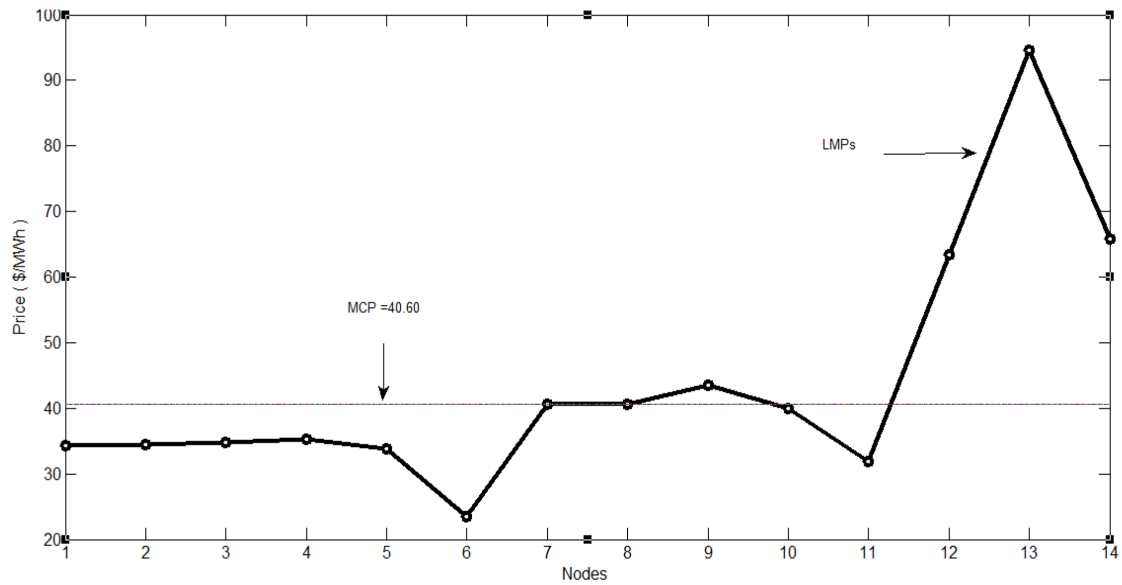

Fig 5.1: LMPs and MCP for 14 bus system without wind power

Two graphs are combined in above graph. The dotted line parallel to X-axis shows the MCP value of 40.60 $/MWh, when network is congestion free. And the other graph shows the fluctuating nodal prices when a constraint of 15 MW was imposed on line from node 6 to 13.The nodal prices at node 6 and node 13 deviates significantly from MCP of 40.60 $/MWhas can be seen from the graph.

5.3 Part- II Simulation Results

The effect of wind power on congestion surplus and on cost of generation is observed here. In Part II, the effects of wind power on the nodal prices of buses which are connected to the constrained line 6-13 in the system are observed. The assumptions made here before simulation are same as stated in 5.2.1. PowerWorld Simulator with same setting as that of part-I was used.

5.3.1 Wind Power- Generation Cost of System

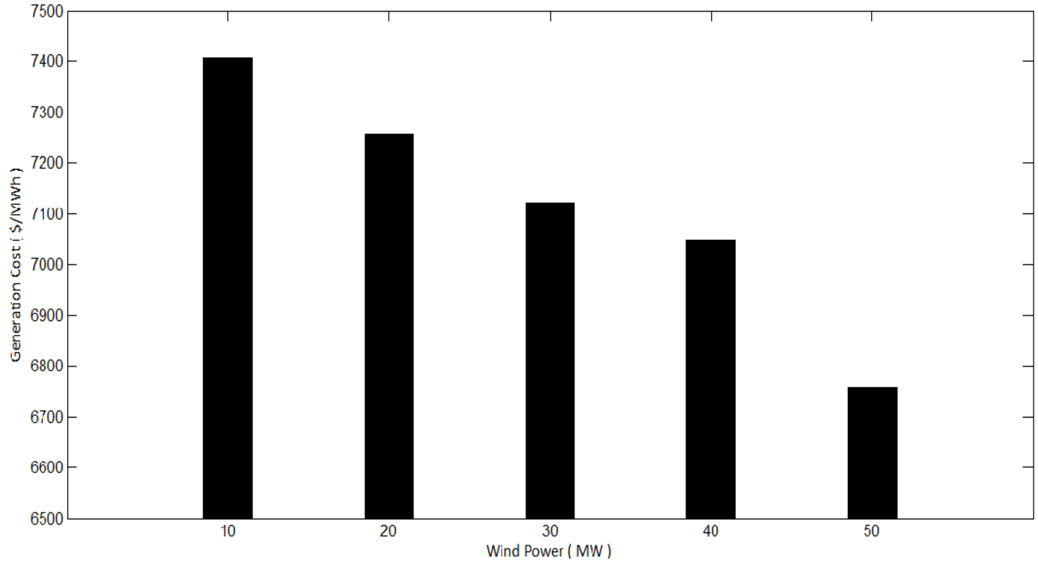

Fig 5.2: Generation Cost vs. Wind Power input at bus 6

In the Fig. 5.2, total bid production cost was plotted against the amount of wind power inducted at node 6 of 14 bus IEEE system. Here wind is price taker. As can be seen from above figure that cost of production is decreasing with induction of wind power. Because more wind power is taken into system, the cost of production by other costly generators is reduced.

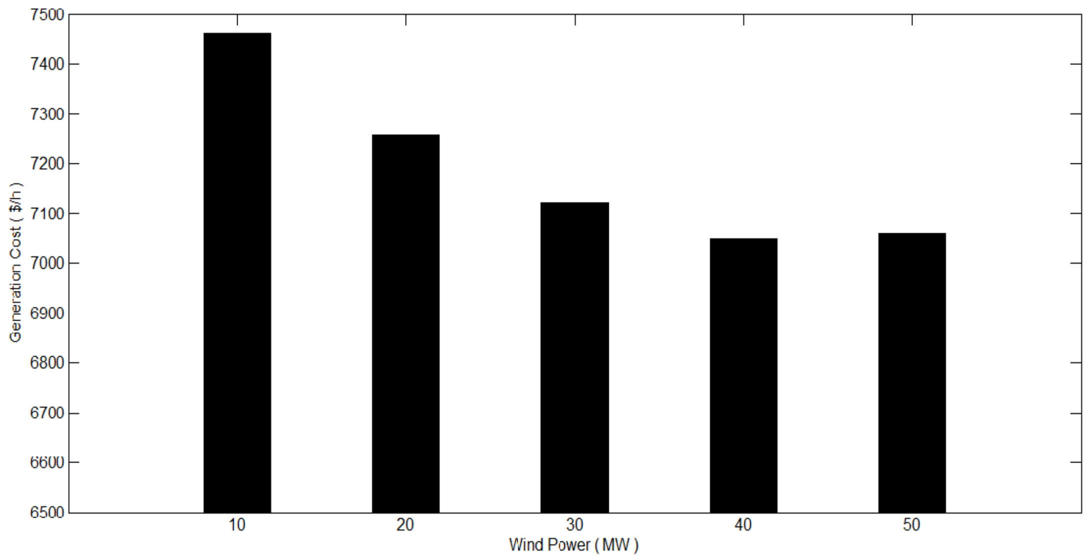

Fig 5.3: Generation Cost vs. Wind Power input at bus 6

In Fig 5.3, total bid production cost was plotted against the amount of wind power inducted at node 6 of 14 bus IEEE system when wind is considered as a part of SC-ED or optimal dispatch solution. The wind is bided at 0 $/MWh while trading. The generation cost decreases with increasing till wind power induction reaches 39 MW. 39 Mw is the optimal amount of wind power to be inducted in system. Till 39 MW, wind power is totally absorbed into system like the previous case when wind power was a fixed schedule. But after 39 MW, no more power is absorbed as it adds to congestion in system. The effect of congestion increases the LMP at other buses, thus increasing the congestion surplus. As we can see in Fig 5.4, there is sudden jump of congestion for wind power greater than 40 MW when wind is taken as price taker. Trading wind as price taker requires wind to be taken in whatever quantity it is available.

5.3.2 Large Scale Integration of Wind Power: Congestion Surplus

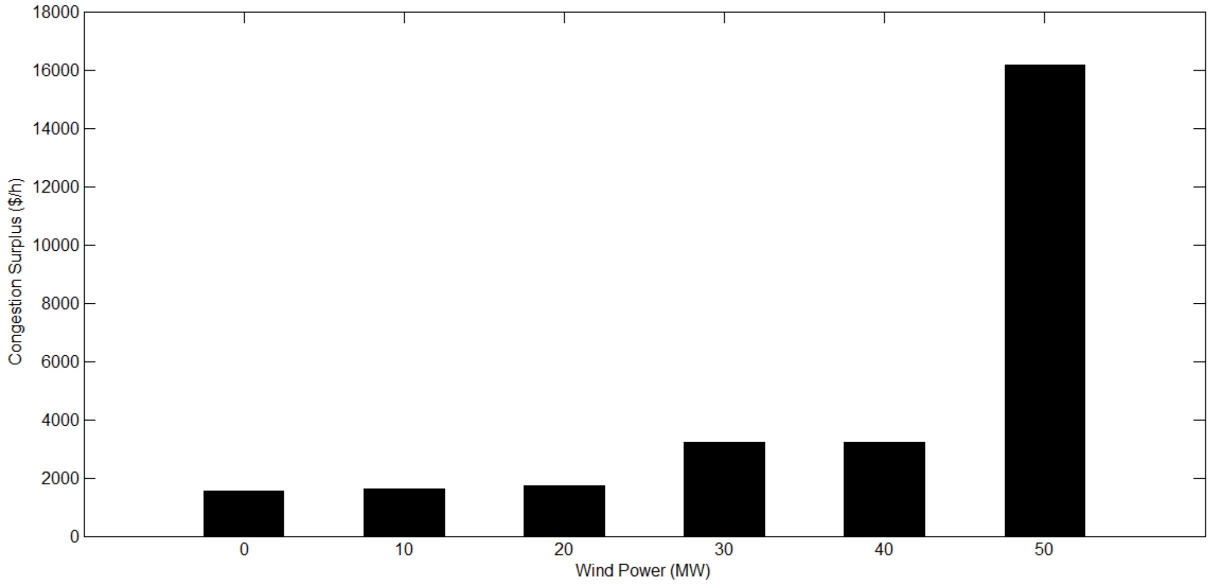

Fig 5.4: Congestion Surplus vs. Wind Power input (fixed schedule) at bus 6

In Fig 5.4, Congestion surplus in system is plotted against wind power inducted at bus 6 which is a fixed schedule. We can see that the congestion surplus is increasing instead of getting decreased. The line connecting bus 6 and bus 13 has constraint and flow of power is from bus 6 to bus 13, hence any addition of power at bus 6, adds to the congestion in system with increased LMP at different nodes in system. After 40 MW, there is a sudden jump in congestion surplus from 3220 $/h to 16156 $/h. The reason for this is stated with description of Fig 5.3. Large scale induction of wind power at bus connected to constrained transmission line increases the congestion surplus of system.

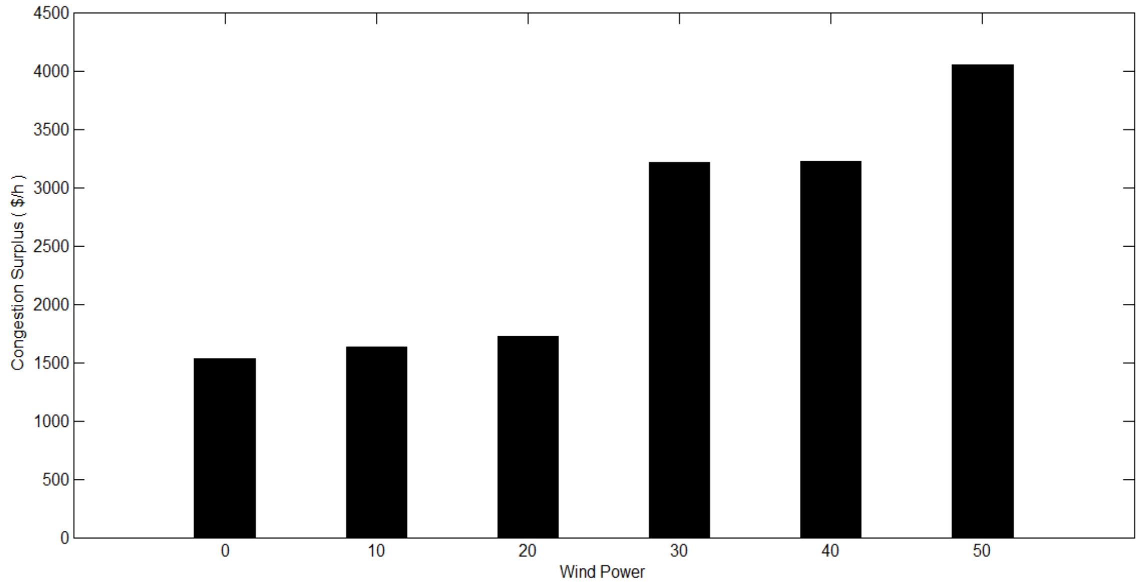

Fig 5.5: Congestion Surplus vs. Wind Power input at bus 6

In Fig 5.5, Congestion surplus in system is plotted against wind power inducted at bus 6 when wind is part of optimal power flow. Congestion surplus is increasing despite wind power is bided in the market at 0 $/MWh for the reasons mentioned in the description of Figure 5.3.

5.4 Simulation results for LMPs

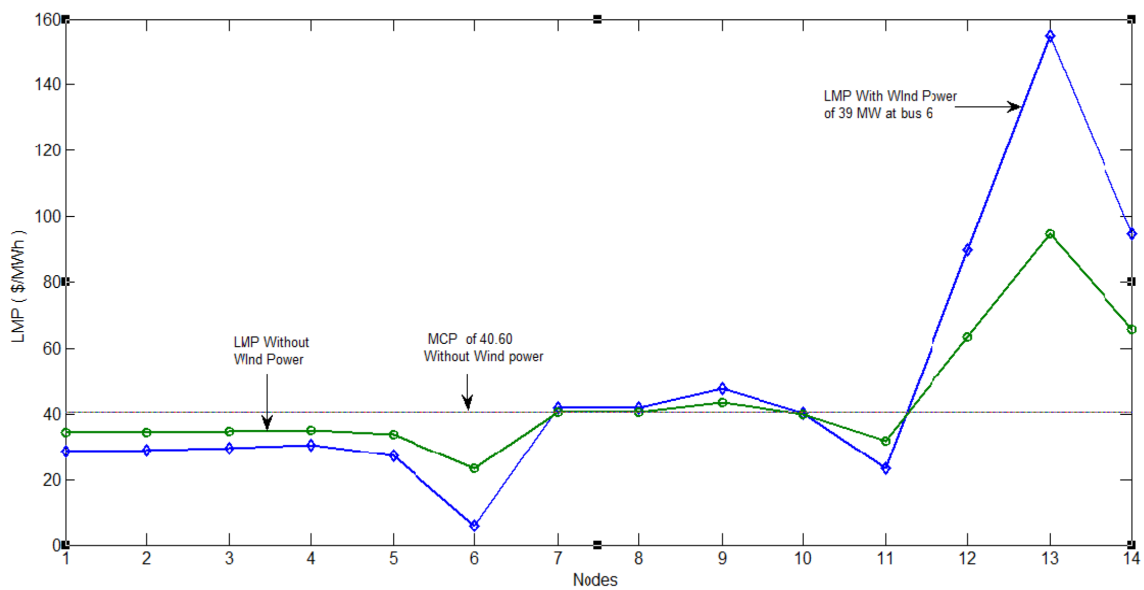

Fig 5.6: LMPs vs Nodes for optimal dispatch of 39 MW of wind power

In the Fig 5.6, the green line is the LMPs at different nodes in 14 bus IEEE system when no wind power is considered for trading. The blue line correspond to the LMPs at different nodes when 39 MW of Wind power is inducted at bus 6 with 0 $/MWh bid rate. The LMP varies drastically from MCp of 40.60 $/MWh at buses 6 and 13, this is because the constrained line in the transmission network of IEEE system connects the buses 6 and 13 and power flows from bus 6 to bus 13. So any addition of real power at bus 6, decreases the LMP at bus 6 and increases the LMP at bus 13 as seen from Fig. 5.6, Fig 5.7, Fig 5.8 and Fig 5.9

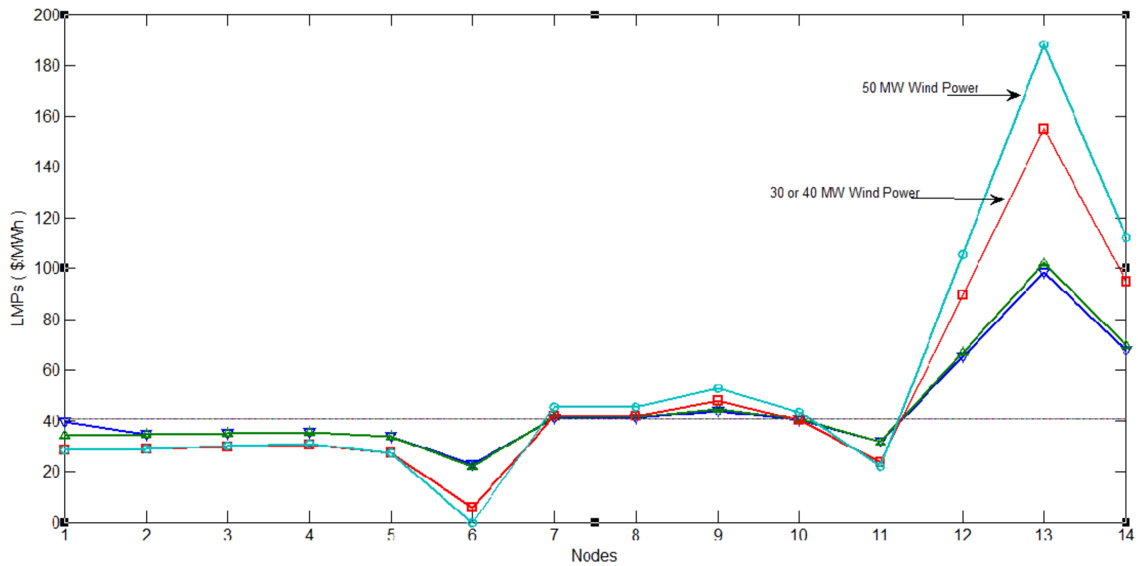

Fig 5.7: LMPs vs Nodes for different wind power input at Bus 6 during OPF

In the Fig 5.7, LMPs were plotted against different nodes for different values of wind power inducted at bus 6. The wind is taken as a part of SC-ED for calculation of LMPs. The values of LMP are same for wind power of 30 and 40 MW. Large deviation of LMPs from MCP is due to large scale integration of wind power.

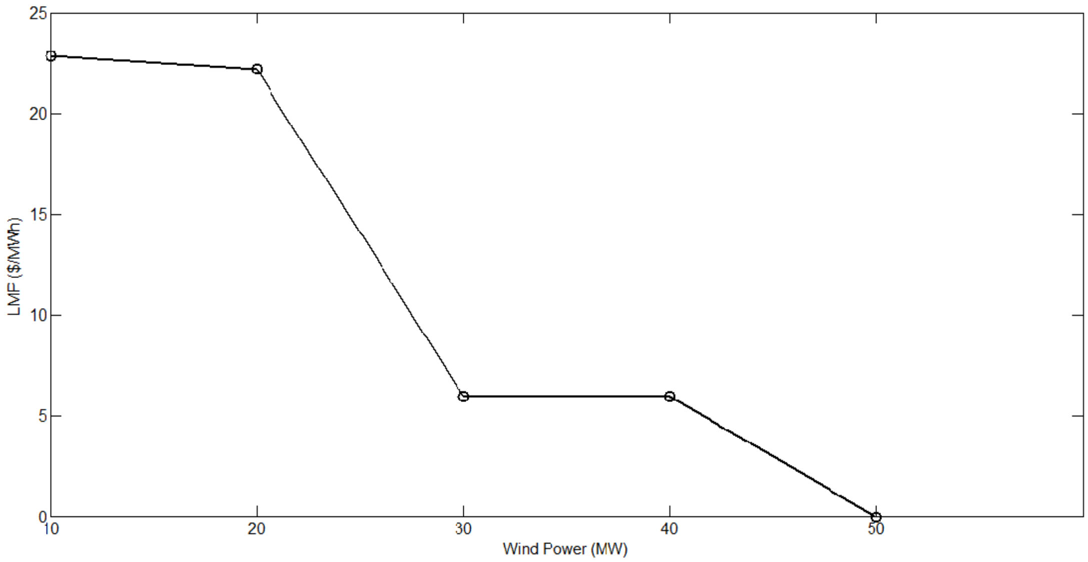

Fig 5.8: LMPs at bus 6 vs different inducted powers during OPF at bus 6

Fig 5.8 shows the various values of LMP at bus 6 when different amounts of wind power is taken as a part of OPF at bus 6. The LMPs at bus 6 are decreasing with increase in wind power and finally reaches 0 $/MWh for 50 MW of wind power.

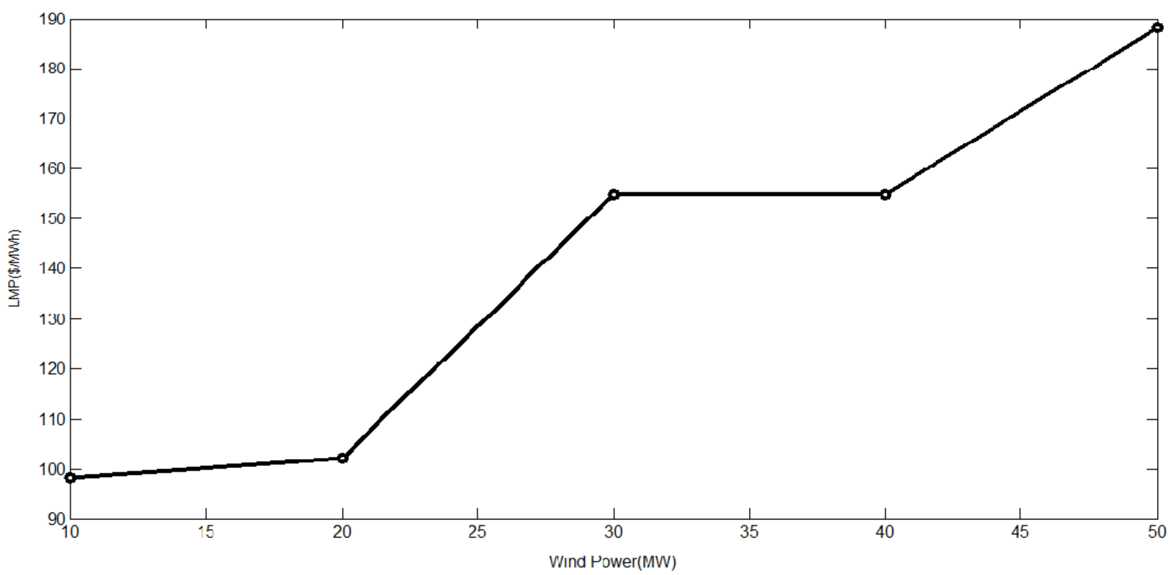

Fig 5.9: LMPs at bus 13 vs different inducted powers during OPF at bus 13

Fig 5.9 shows the various values of LMP at bus 13 when different amounts of wind power is taken as a part of OPF at bus 13. The LMPs at bus 13 are increasing with increase in wind power and finally reaches 188 $/MWh for 50 MW of wind power.

5.5.1 Observation

1. The cost of production of generation decreases from 7732.67 $/h, when wind was not traded in the system, to 7058 $/h when wind was made part of optimal dispatch. And amount paid by electricity buyers increases from 10626 $/h , when wind was not traded in the system, to 12022 $/h when wind was made part of optimal dispatch.
2. The maximum amount of wind power that was absorbed at bus 6 when it was part of SC-ED is 39 MW.
3. Congestion Surplus increases from 1531 $/h, when wind was not traded in the system to 4054 $/h when wind was made part of optimal dispatch.
4. The LMPs in fig 5.1 deviates from MCP 40.60 $/MWh drastically and deviation increases as wind power induction increases as can be seen from Fig 5.6 and Fig 5.7.

5.5.2 Summary

1. This result of decreases in the cost of production of electricity and increase in the consumer payments is in accordance with the similar result that was obtained in 4th chapter of this thesis. Increase in total surplus in the market indicates the efficient allocation of resources (electricity), which is the primary objective of SO.
2. 39 Mw is the optimal amount of wind power to be inducted in system at bus 6.
3. Large scale integration of wind power at bus 6 has caused the increase in congestion surplus and efficient congestion management method is required to deal with it.
4. Congestion has led to price volatility and system instability, which can deteriorate the electricity market operation.

The 14 bus IEEE system shows the same results like decrease in the cost of production and increase in the generation revenue, as that of chapter 4 except the increase in congestion surplus due to large scale integration of wind power at bus 6. The congestion surplus comes at the cost of decrease in social/total surplus. Minimizing congestion surplus will increase the total surplus.

Hence congestion management method is required. Also congestion increases the price volatility leading to system instability. A suitable mechanism is proposed in the next chapter for the same

Chapter 6

Congestion Management Method with Demand Elasticity for Wind Power

6.1 Introduction

In the deregulated market, congestions are encountered with higher frequency than before. Congestion As seen from the last chapter that wind power trading increases the congestion surplus when inducted at buses which are connected to the constrained transmission line. In this chapter we will try to decrease this congestion surplus by using a congestion management method.

6.2 Demand Elasticity

The demand elasticity, so-called price elasticity of demand is an important index which measures the level of demand response of the product following its price change. The algorithm for calculation of the demand elasticity is defined as the percentage change in demand quantity divided ($\Delta P / P$) by the percentage change in price ($\Delta\rho / \rho$), as shown below :

$$e = -\frac{\rho}{P}\frac{\Delta P}{\Delta\rho} \tag{6.1}$$

Demand usually rises inversely proportional to the price the demand elasticity is negative in general. The economist usually put it into minus sign to better reflect its meaning and to indicate that an increase in price would result in an reduction in demand. The equation below presents the demand elasticity of the consumer at bus i.

$$e({P_i}^d) = -\frac{{\rho_i}^d}{{P_i}^d}\frac{dP^d}{d\rho^d} \tag{6.2}$$

In the above equation, $e({P_i}^d)$ is demand elasticity at bus i, ${\rho_i}^d$ is the demand price of the bus i and ${P_i}^d$ is the demand at bus i. Demand can be categorized into the following four types according to the level of demand elasticity:

1. . If e=0, the demand is considered as absolutely inelastic which means the demand would not change with the price change. The demand curve is vertical
2. If 0<e<1, the demand is defined as inelastic while the demands would change in smaller portion with the price change.
3. If e=1, the demand is said to have unit elasticity. The portion of demand variance is equal the portion of the price change.
4. If e>1, the demand is elastic and the change of price would lead to a larger margin impact on the demand.

By convention, the demand bid curve is expressed as the following linear function:

$$\rho_i{}^d = b_{2i}P_i{}^d + b_{1i} \quad (6.3)$$

Where b_{2i}, b_{1i} are parameters of individual load and b_{2i}<0
The corresponding benefit function of bus i, which represents the benefits that customers receive from consuming $P_i{}^d$ MWh of electricity power at bus i, can be derived by integration of the demand bid curve as expressed below:

$$B_i(P_i{}^d) = \frac{1}{2}b_{2i}(P_i{}^d)^2 + b_{1i}P_i{}^d + b_{0i} \quad (6.4)$$

According to the definition of the demand elasticity, load demand elasticity can be rewritten as below:

$$e(P_i{}^d) = -\frac{b_{1i}}{b_{2i}\ P_i{}^d} - 1 \quad (6.5)$$

But $b_{2i} < 0$, therefore

$$e(P_i{}^d) = \frac{b_{1i}}{b_{2i}\ P_i{}^d} - 1 \quad (6.6)$$

$$e(P_i{}^d) + 1 = \frac{b_{1i}}{b_{2i}\ P_i{}^d} \quad (6.7)$$

For e=0, $P_i{}^{d^o} = \frac{b_{1i}}{b_{2i}}$

$$\frac{1}{e(P_i{}^d) + 1} = \frac{b_{2i}\ P_i{}^{d^{new}}}{b_{1i}} \quad (6.8)$$

$$\frac{b_{1i}}{(e(P_i{}^d) + 1)b_{2i}} = P_i{}^{d^{new}} \quad (6.9)$$

$$\frac{P_i{}^{d^{o}}}{(e(P_i{}^d) + 1)} = P_i{}^{d^{new}} \quad (6.10)$$

From the above equations, various values of demands elasticity of 0, 0.1,0.2 are derived at buses 1,2,3,6. And data of Table 5.1, IEEE 14 bus data in [15] and changed demand data derived from (6.10) because of elasticity are used to perform the simulations.

6.3 Simulation Results

Same assumptions as used in 5.2.1 are used for performing SC-ED in PowerWorld Simulator. In the last chapter, demand response was not considered while performing Primal LP OPF. Values of generation cost of production at bus 6, congestion surplus at bus 6 are obtained by simulating the 14 bus IEEE system for different values of demand price elasticity, to understand the effect of elasticity.

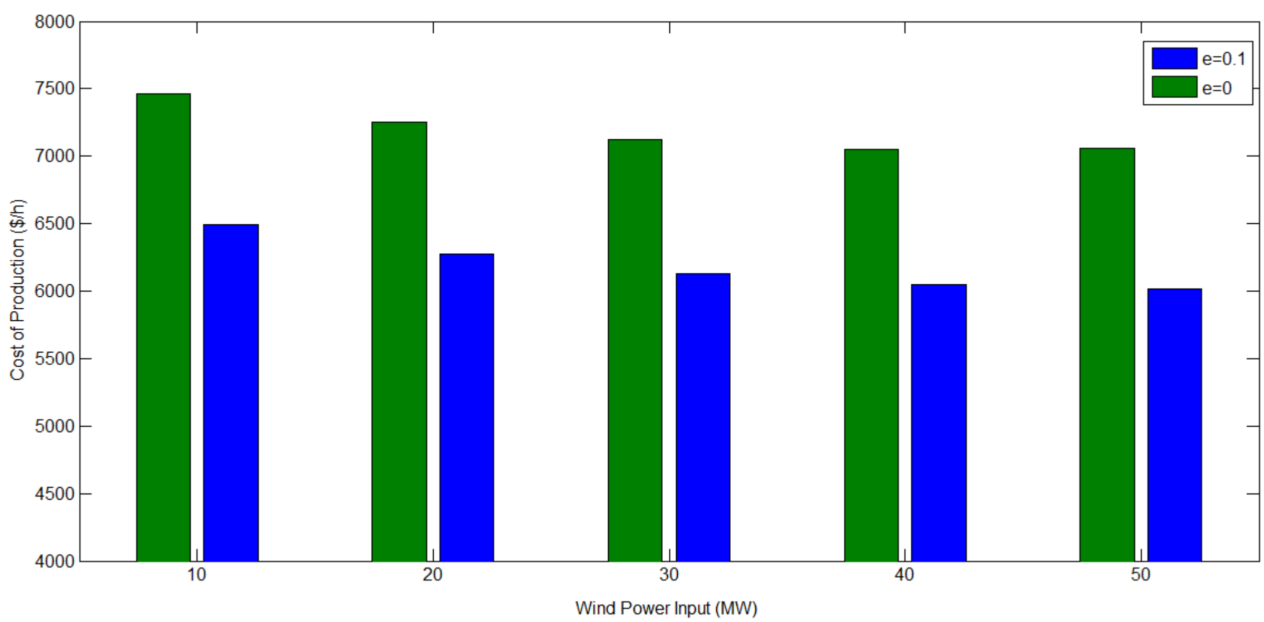

Fig 6.1: Cost of production vs. Wind Power Input at bus 6

In Fig 6.1, the generation cost of production of electricity is plotted against different amounts wind power inputs at bus 6 for two values of demand elasticity. The blue bar denotes the cost of production associated with demand elasticity (e) equal to 0.1 and green bar denotes with e=0. Cost of production is decreased further as demand elasticity is increased from 0 to 0.1.

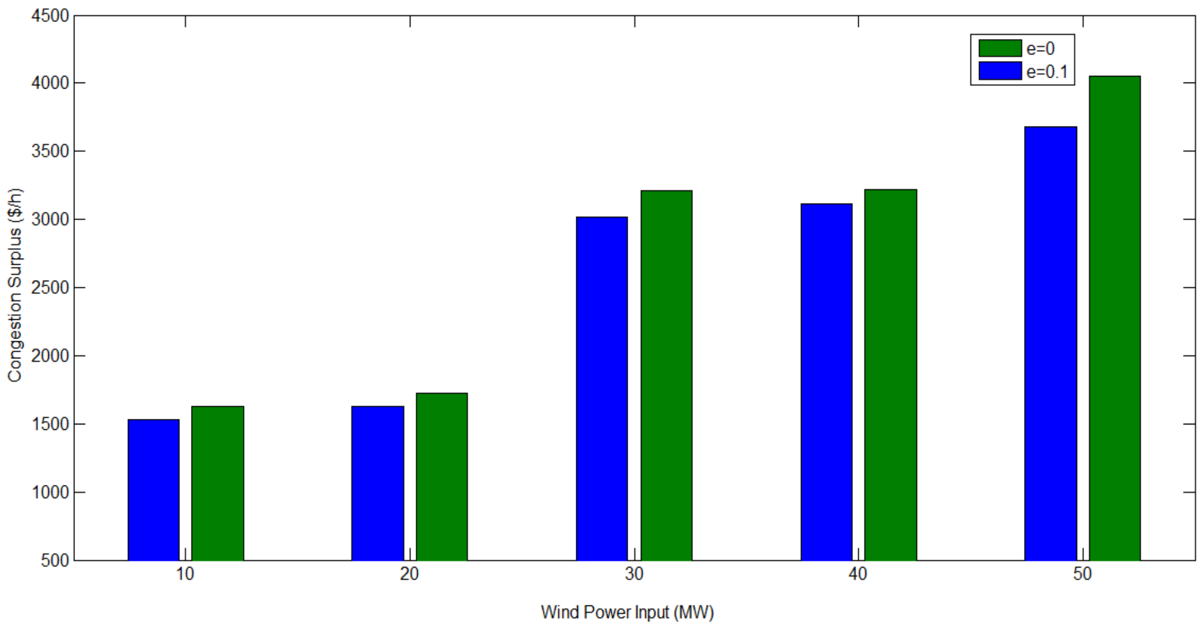

Fig 6.2: Congestion Surplus vs. Wind Power Input at bus 6

In Fig 6.2, congestion surplus of system is plotted against different amounts wind power inputs at bus 6 for two values of demand elasticity. The blue bar congestion surplus associated with demand elasticity (e) equal to 0.1 and green bar denotes with e=0. As can be seen from Fig 6.2 congestion surplus is less for every input amount of wind power for demand elasticity of 0.1 as compared to demand elasticity of 0.

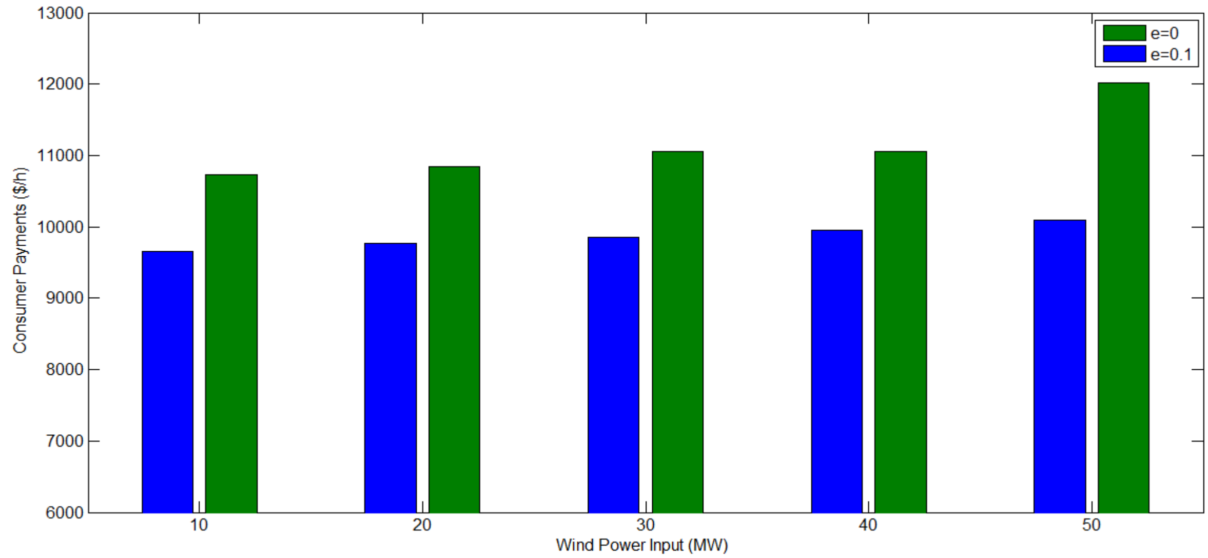

Fig 6.3: Consumer Payments vs. Wind Power Input at bus 6

In the above Fig 6.3, consumer payments are plotted against the wind power input for e=0 and e=0.1. The consumer payments have decreased for the case of e=0.1 as compared to e=0.

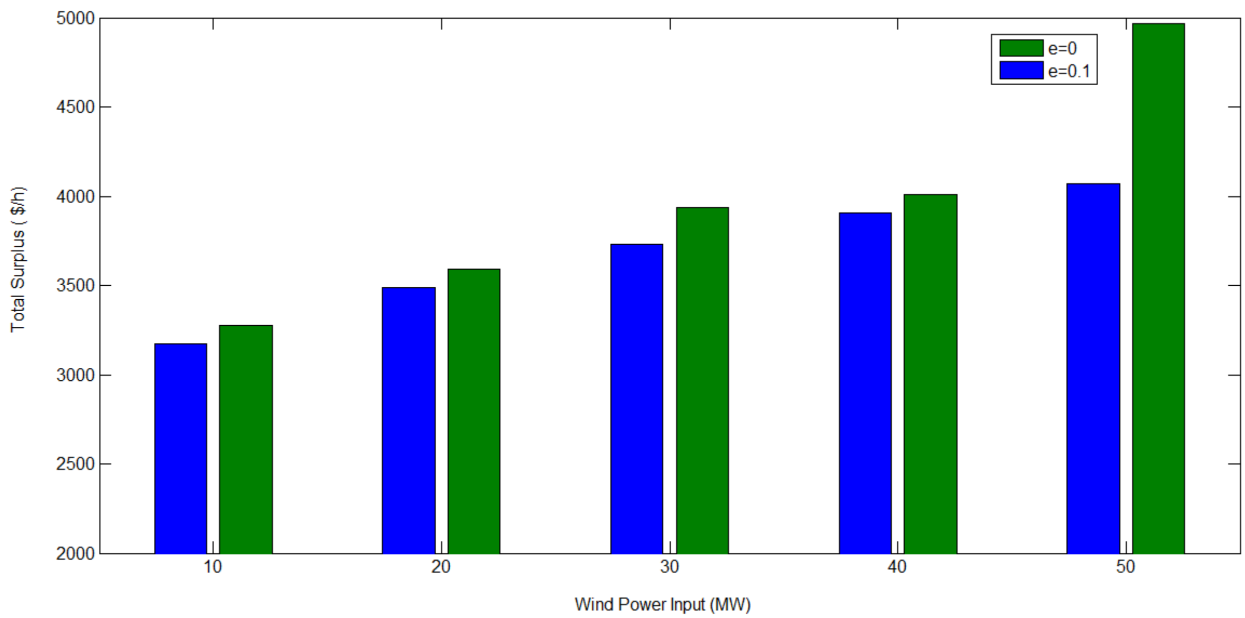

Fig 6.4: Total Surplus vs. Wind Power Input at bus 6

In the above Fig 6.4, total surplus/social surplus has been plotted against the wind power input at bus 6.Total Surplus is less in case of e=0.1 as compared to e=0 for various wind power as seen from the graph.

6.4 Simulation Results: Demand Elasticity at Node 13

It is not possible to apply demand elasticity at all the nodes in the complex power system. The introduction of demand elasticity at a specific node with a high influence on power flow in congested branches would relieve the congestion efficaciously. The buses 6 and 13 are connected to the constrained line and node 13 contributes most to the net flow on line 6-13. Hence, the demand elasticity is introduced only at node 13.

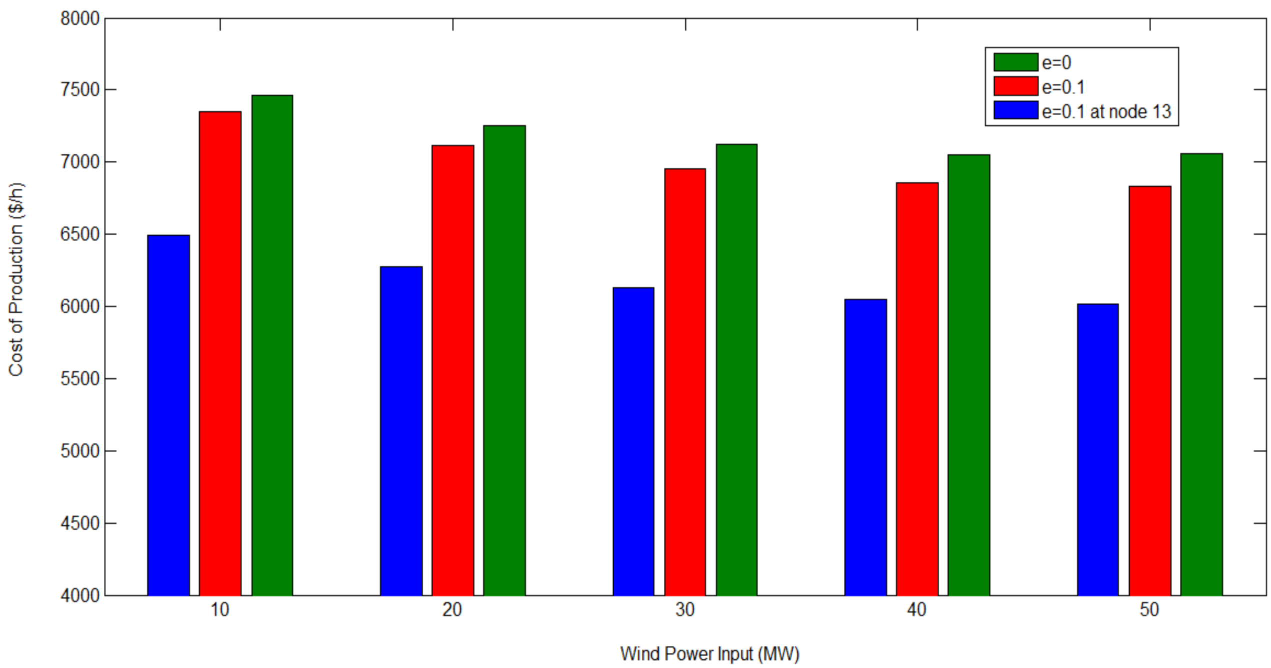

Fig 6.5: Generation Cost vs. Wind Power Input at bus 6

In Fig 6.5, cost of generation of electricity is plotted against wind power input at bus 6. The three demand elasticity's of e=0, e=0.1(for all nodes) and e-0.1(only for node 13) are taken for simulation of case study. The generation cost is minimum among all and decreasing with wind power for e=0.1(all nodes), maximum and decreasing with wind power input for e=0 and in between these two and decreasing with wind power input for e=0.1(for node 13).

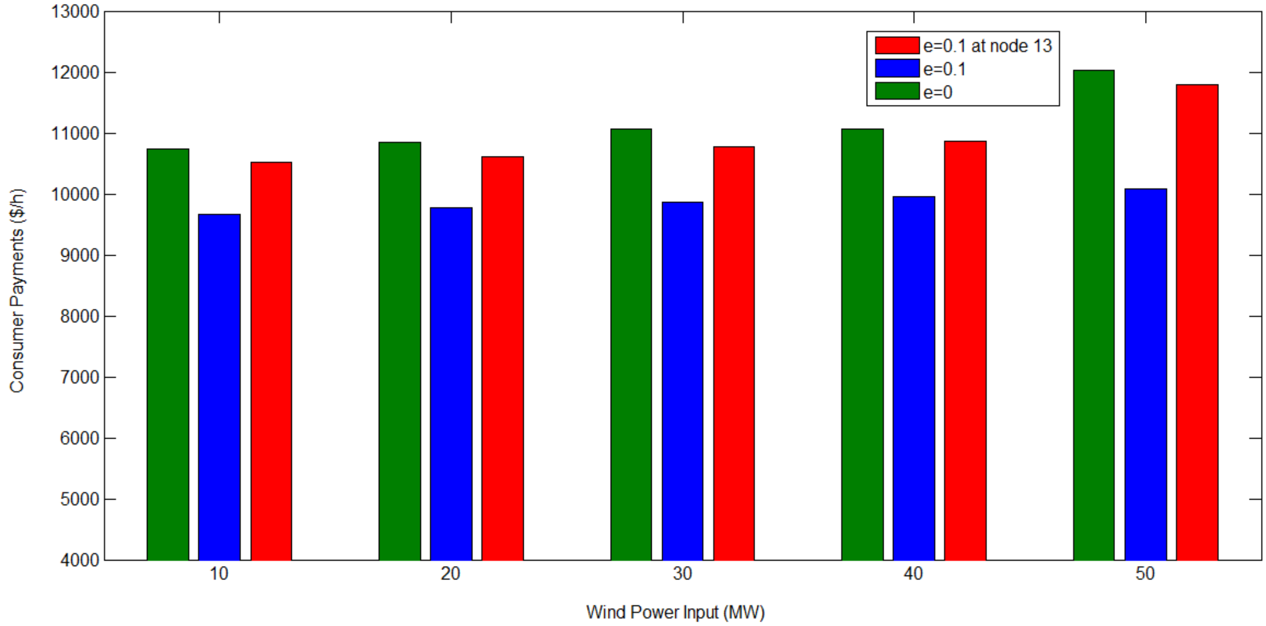

Fig. 6.6: Consumer Payments vs. Wind Power Input at bus 6

In the Fig 6.6, Consumer payments are plotted against wind power input at bus 6.For e=0, consumer payments are highest and for e=0.1(for all nodes), consumer payments are lowest. For e=0.1 (for node 13) it's in between other two cases.

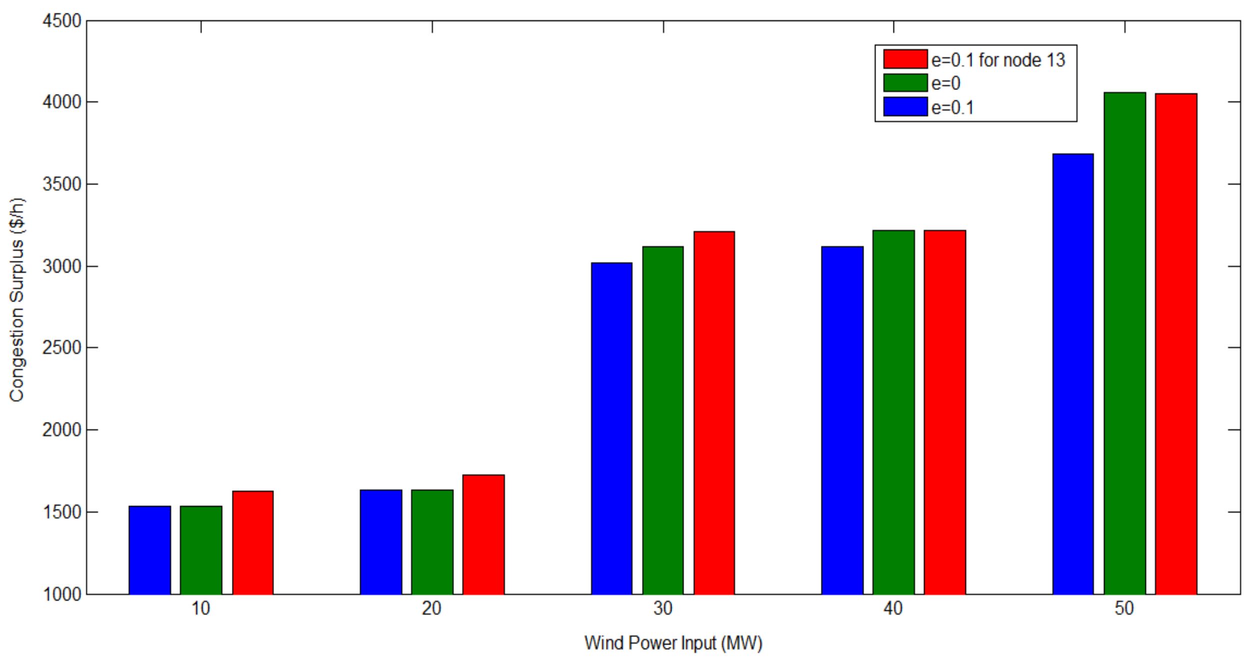

Fig. 6.7: Congestion Surplus vs. Wind Power Input at bus 6

In the Fig 6.7, Congestion surplus has been plotted against wind power input at bus 6 for different values of demand elasticity. Congestion surplus in case demand elasticity applied only at bus 13 is more as compared to the congestion surplus when demand elasticity is applied at all the nodes.

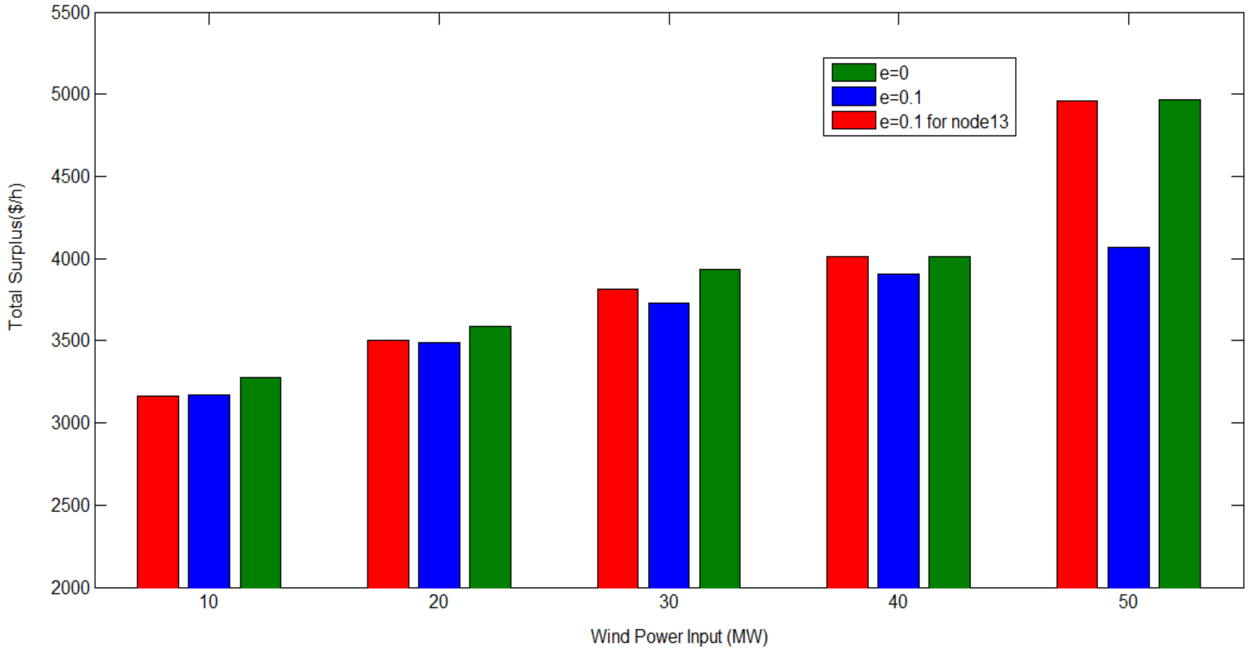

Fig 6.8: Total Surplus vs. Wind Power Input at bus 6

In Fig. 6.8, total surplus is plotted against different wind power inputs at bus 6 for e=0,e=0.1 applied at node 13 and e=0.1 applied at all nodes. As can be seen from the graph, total surplus is more for the case of e=0.1 for node 13 as compared to the e=0.1 for all nodes. At 50 MW total surplus is almost equal for cases of e=0.1 for bus 13 and e=0 for all nodes.

6.6 Summary

1. Congestion has decreased when demand elasticity of 0.1 was applied on all nodes.
2. Decrease in congestion surplus has come at the cost of decrease in total surplus.
3. Total Surplus with demand elasticity is nearby to the values of total surplus when demand elasticity is 0 till 40 MW. But after that difference in total surplus jumps up drastically

Using demand elasticity at one node might not be a good option when large quantities of wind is considered Using wind power a part of SC-ED helps in decreasing the cost of operation and Increases the consumer payments. Both the effects increase the total surplus of system, a necessary sign for efficient allocation of wind power in electricity market. But large scale integration of wind power increases the congestion and also decreases the total surplus. So the work in this chapter can be useful for SO, as a guideline on what amount of wind power has to be allowed for trading.

Chapter 7
Conclusions

7.1 Summary and conclusions

In the thesis the whole project is divided into 6 chapters. Each chapter has a good contribution towards the deriving the knowledge required for concluding on the effects of wind power trading in electricity market. The second chapter introduces to the some of the important concepts required for understanding the remaining chapters. The wind as such has many problems when it comes to trading. Some of these problems are tackled in different chapters of the thesis.

Chapter 3 dealt with facilitating the integration of wind power into electricity market trading. Wind is taken as a price taker here, as a fixed schedule. A strategy has been proposed for wind power trading in the same chapter. The proposed method can be useful for increasing the wind power revenues. The strategy demands consumers to pay more so that more money remains with SO and can help in increasing the revenues of Wind power producers by getting a good price, which generally end up getting negative prices in the market. The proposed strategy is based on the concept of MCP. But a real world market is more complex and has LMPs or different prices for different participants depending upon the geographical area where the producer is connected to the grid. So the third chapter dealt with facilitating wind power integration and increasing wind producers revenues and has achieved the objective 1.

Chapter 4 dealt with a case study on a small congested three bus system which took wind power both as a part of SC-ED and price taker. The benefits of using wind power as price taker ans part of optimal power flow were compared. Using wind power a part of SC-ED, resulted in reducing cost of production of electricity and increasing the consumer payments. This chapter justified the requirement of using wind power as a part of optimal power flow with the help of results derived from simulations performed by PowerWorld simulator. The objective 2 was achieved.

Chapter 5 dealt with the application of knowledge acquired in chapter 4, on a large, congested 14 bus IEEE system. The 14 bus IEEE system showed the same results like decrease in the cost of production and increase in the generation revenue, as that of chapter 4 except the increase in congestion surplus due to large scale of integration of wind power at bus 6. The congestion surplus came at the cost of decrease in social/total surplus. Minimizing congestion surplus will increase the total surplus. Hence congestion management method is required. Also congestion increases the price volatility leading to system instability. A suitable mechanism was proposed in the next chapter for the same. The objective 3 is achieved.

From the chapter 5, the only problem remaining with large scale integration of wind power into 14 bus IEEE system was the increase in the congestion surplus. Chapter 6 dealt with using the knowledge acquired from previous chapters and proposed a congestion management method of demand elasticity to reduce the congestion surplus increase. The method successfully decreased the congestion surplus when demand elasticity was applied to all nodes in the system, but was unsuccessful when demand elasticity was applied only to the concerned node 13 which is connected to the constrained transmission line. So by and large the aim of increasing the social surplus or maximizing the social welfare was achieved considerably when wind power traded in the electricity market. So the objective 4 was achieved.

7.2 Project Contributions

The project deals with how wind power affects the prices of electrical power at different nodes in 14 Bus IEEE system as well as simple three bus system and how the merchandizing surplus of these test systems will change when subjected to the small scale as well as large scale integration of wind power.

Power World Simulator was used throughout the project to calculate the LMPs and merchandising surpluses in test systems. The different graphs like of nodal prices variation with respect to nodes and congestion surplus, consumer payments ,cost of generation vs. wind power input at bus 6 were drawn to understand the behavior of changes in LMPs at nodes, the changes in congestion surplus, total surplus in different test systems when various amounts of wind power was used.

The project work is solely based from SO' point of view for maximizing the total surplus of power system taking into account system security and reliability. The project work can be a guideline for SO as well as policy makers for changing roles of wind power in electricity market.

7.3 Suggestions for future work

The problem that remains is a congestion management method which can decrease the congestion surplus further and increase the social surplus. Also the system is assumed to be lossless with zero resistances in transmission network. A transmission loss prone system can be taken to perform SC-ED. It can be made more realistic by considering reactive power for calculating LMPs in the market, by not keeping voltage profile flat, by having considerable difference in the angles at different nodes. The effect of wind power on congestion surplus, cost of production of electricity and consumer payments can be observed for such a system. The necessary knowledge for running the electricity market can be derived by performing OPF on more realistic power system.

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