An Operating Model and Economic Analysis for Integrating Wind Electric Power in Manufacturing

by

Komkrit Pitiruek

A dissertation submitted to the Graduate Faculty of
Auburn University
in partial fulfillment of the
requirements for the Degree of
Doctor of Philosophy

Auburn, Alabama
May 9, 2011

Keywords: wind energy investment, manufacturing operations, power network system

Approved by

Jorge F. Valenzuela, Chair, Associate Professor of Industrial & Systems Engineering
Chan S. Park, Daniel F. and Josephine Breeden Professor of Industrial & Systems Engineering
Saeed Maghsoodloo, Professor of Industrial& Systems Engineering

Abstract

Among the renewable sources of generating electricity, wind power costs less to produce and produces fewer CO_2 emissions. In addition, the Department of Energy (DOE) has stated that wind power should provide 20% of U.S. electricity by 2030. These make wind power a very promising investment for the next two decades. Investment in wind power is an opportunity not just for power producers but for manufacturing facilities as well. However, integrating wind electric power into the existing power system network is still questionable due to the variability of wind power output. Since the government offers tax incentives such as the federal production tax credit, the cost disadvantage could be overcome, and wind energy investment could be profitable. In addition to offsetting costs through a tax credit, a manufacturing facility investing in wind turbines can help to reduce its energy costs whether it self-generates part of its energy consumption or sells the surplus electric power generated by the wind turbines into the power market.

In order to invest in wind power, facilities need an economic analysis of wind energy investment under real-time pricing, and this dissertation develops a system operating model for a manufacturing facility that represents the interaction between a manufacturing facility's energy usage and a power network system. Two system operating models and economic analysis formulations of wind farm investment are introduced. The first System Operating model (SO-A),

using mathematical programming with complementarity constraints (MPCC) approach, represents operations more accurately but is inconvenient to use in a long-term study. The second System Operating model (SO-B), using the interrelated linear programming (LP) technique, is developed to overcome the SO-A's disadvantages and is easier to solve, so it is better for a long-term study. However, the outputs of the SO-B are inaccurate. Therefore, correction models are then constructed to adjust the differences between the outputs of the two models. Wind farm investment formulations for different scenarios are also formulated for an economic analysis. The models are tested using a 5-Bus, 4-Generator Power System. Using this power system, 2 wind farms, and 2 manufacturing facilities, the results show that wind power investment provides economic benefits to the manufacturing facilities in either purchasing or generating part of their energy using wind power. Investing in a wind farm project is preferable for the manufacturing facility in terms of the annual equivalent cost reduction. For the power generating company, including wind power in the power network results in reducing the company's annual profit. If the power system must include a wind farm, then the best alternative for the power generating company is to own the wind farm.

Acknowledgments

Without support and encouragement, I could have never completed this work. First and foremost, I would like to thank my advisor Dr. Jorge F. Valenzuela for his precious support and guidance all along my doctorate experience as well as for shaping my life. Without his support, I would never be what I am today. Special thanks go to Dr. Chan S. Park who has given me invariable generosity and opportunity to collaborate and experience several engineering economics classes, and to Dr. Saeed Maghsoodloo who has always given me constant encouragement and invaluable experience on my first time job as a Teaching Assistant. Next, I would like to thank all my INSY friends as well as the entire faculty and staff who participated in my life and made my years in Auburn memorable.

Finally, I would like to thank my parents Supakorn and Napak for giving me my life and for their unconditional love, to my bother Chanudom and my sister Napakun for their indefinite support.

We shall not cease from exploration. And the end of all our exploring will be to arrive where we started and know the place for the first time.

- T.S. Eliot

Table of Contents

List of Tables

List of Figures

Nomenclature

Indexes

j: Index for lines j; $j = 1..M$

k: Index for buses k; $k = 1..K$

t: Index for hours t; $t = 1..T$

f: Index for facilities f; $f = 1..F$

d: Index for days d; $d = 1..D$

Parameters

λ_t: System energy price ($/MWh) in SO-B model

I_f^{cost}: Inventory cost of facility f ($/unit of volume/h)

I_0^f: Initial inventory of facility f (unit of volume)

CP_f: Manufacturing capacity facility f (unit of volume/h)

D_f: Total demand of facility f (unit of volume)

E_f: Maximum energy consumption by facility f (MW)

M: Number of lines

K: Number of buses

T: Number of hours

F: Number of facilities

D: Number of days

C_k: Energy cost of generator k (\$)

A_j^k: Power Transfer Distribution Factor (PTDF) at line j from node k to hub

$F_{j,t}^{max}$: Maximum power flow at line j and hour t (MW)

$G_{k,t}^{min}$: Minimum generation of generator k at hour t (MW)

$G_{k,t}^{max}$: Maximum generation of generator k at hour t (MW)

$W_{k,t}$: Expected wind power at bus k and hour t (MW)

$W_{k,t}^{max}$: Maximum wind power available at bus k and hour t (MW)

N: Number of periods of cash flow

d: The day in which the revenue (cost),X_d occurs

I: Initial cost of wind farm

S: Salvage value of wind farm

C: Number of interest periods per payment period

K: Number of payment periods per year

PT: Tax credit for each kWh of wind electric power generated

$W_{k,d,t}$: Expected wind power at bus k in day d at hour t (MW)

$W_{k,d,t}^{max}$: Maximum wind power available at bus k in day d at hour t (MW)

Decision Variables

λ_t: System energy price ($/MWh) in SO-A model

P_t: Location Marginal Price at bus k and hour t ($/MWh)

$i_{f,t}$: Inventory level of facility f at hour t (unit of volume)

$u_{f,t}$: Machine schedule of facility f at hour t

$g_{k,t}$: Energy dispatched by generator k at hour t

$L_{k,t}$: Load at bus k and hour t with manufacturing facility scheduling (MW)

PR_d: The daily revenue of power generating company in day d

PC_d: The daily cost of power generating company in day d

$FC_{f,d}$: The daily cost of facility f in day d

$g_{k,d,t}$: The amount of electricity dispatched from generator k in day d at time t

$P_{k,d,t}$: The daily Locational Marginal Price on bus k in day d at time t

$i_{f,d,t}$: Inventory level of facility f in day d at time t

$u_{f,d,t}$: Operational schedule of facility f in day d at time t

PW: Present worth of daily revenue (cost)

AE: Annual equivalence (worth, revenue, and cost)

CR: Capital recovery cost

X_d: Revenue (cost) in day d

i: Effective interest rate

r: Nominal interest rate

Dual variables

$\mu_{j,t}^{+/-}$: Dual variables of power flow constraints

$\beta_{k,t}$: Dual variables of generator k at hour t

CHAPTER 1

INTRODUCTION

Renewable sources for generating electricity are becoming more economically attractive than other sources of energy. In the near future, it is expected that the cost of renewable energy will be cheaper than fossil fuels, primarily because once the power plant is constructed, the fuel is free afterward. Furthermore, the trend towards using renewable energy is increasing worldwide. Once the world commits to shifting toward renewable energy, the cost of equipment such as wind turbines and solar panels is expected to decline. Moreover, government tax incentives such as the federal production tax credit (PTC) [1] can also make renewable energy preferable.

Among the various renewable energy sources, wind power provides the lowest production cost [2] and smallest environmental impact [3]. Electricity generated by wind power is not a new technology in the U. S. The wind industry started in California during the 1970s during the oil shortage crisis, and, since then, U.S. wind power generation has been increasing. Recently, wind power installed in the U.S. surpassed 35,159 MW. For the first quarter of 2010, approximately 1% of electricity generated in the US was fueled by wind energy. This percentage is expected to grow further, as the Department of Energy has stated that wind power should provide 20% of U.S. electricity by 2030 [4].

Wind power seems to be a very promising investment for the next two decades. Investment in wind power is an opportunity not just for power producers but for residential consumers and manufacturing facilities as well. A do-it-yourself wind turbine with a capacity of about 1kW or less is available for residential consumers so they can install their own wind turbine. Similarly, large scale wind turbines are available to manufacturing facilities.

Though investment in wind turbines can be steep, a manufacturing facility can offset these costs through the federal production tax credit as well as benefit directly and indirectly in reduction of its energy costs. For a direct benefit, the facility spends less on purchasing energy from a power producer since the facility would self-generate part of its energy consumption. For an indirect benefit, the surplus of electric power generated by the wind turbines, if any, can be sold into the power market. In this case, the facility would make an additional profit by selling energy. Another indirect benefit is that the the wind turbines could help to reduce transmission congestion and consequently reduce the market energy price that the facility pays for its energy when the wind turbines do not supply all the energy required for the operation of the manufacturing plant. In addition, a wind turbine does not produce air and water pollution. Therefore, CO_2 emissions would be reduced [3], and benefits would be shared by all consumers on the power network.

In general, consumers, both residential and commercial, pay a flat rate for the electric energy that they consume over a period of time. The energy cost is calculated by the total electricity consumed multiplied by the energy rate. When manufacturing facilities pay a flat rate, operation of manufacturing processes can be scheduled without considering the price of energy.

However, a new practice for pricing electric energy, called real-time pricing, is currently being introduced with the development of new metering technology. Real-time pricing requires the use of a smart meter, an electronic device that records electricity consumption and the time of the consumption and then sends the information to the power supplier for monitoring and billing purposes. The real-time electricity price is determined by the Locational Marginal Price (LMP) approach [5], which consists of system energy price, transmission congestion cost, and cost of marginal losses. It is believed that real-time pricing can reduce peak demand, which in turn could impact electricity cost saving. If peak demand occurs when the power company charges a flat rate, the power company will lose profits because peaking generation units usually generate a higher marginal cost. Spees and Lave's study [6] has shown that reducing approximately 1% of the PJM Interconnection LLC (PJM) daily peak demand would result in savings of 3.5% of base expense of customers' annual billing. In addition, the Power of Five Percent of the Brattle group [7] reported that as little as a 5% drop in peak demand in the United States would yield an annual savings of $3 billion for the next twenty years.

The savings to the manufacturers using real-time pricing could be significant. However, in this case the price of energy needs to be considered when scheduling operations of the manufacturing facilities. Operations should be adjusted according to the prices of their energy usage. The facility should respond to real-time prices by turning off the machines at times of high prices and turning on the machines at comparatively low-price hours while keeping the total amount of energy consumption unchanged over the scheduling period. This information should be considered in conjunction with production of energy by wind, but the facility needs a precise analysis of their potential wind power investment.

The main purpose of this dissertation is to develop an operating model for a manufacturing facility which pays real-time energy prices and to perform an economic analysis of wind energy investment. The main purpose of constructing an operating model is to obtain dependable information for a manufacturing facility to observe the entire system and to provide the decision makers with information to plan their manufacturing operations on a daily basis. The system operating model is used by one facility and treats energy consumption at other facilities as known loads. The OPF model is used to obtain energy prices. It considers the schedule of the manufacturing operations in order to compute the energy prices. The operating model is formulated as a bilevel programing model. To solve the operating model, the first order KKT conditions of the OPF model are obtained and then added to the manufacturing scheduling model. The resulting operating model becomes a quadratic program with complementarity constraints, which represents the actual relationship between the manufacturting facilities and the power system. The model is very difficult to solve and very inconvinient to use for long-term studies. Therefore, another system operating model is developed to approximate the first system operating model with more simplicity.

The main reason to perform an economic analysis is to obtain reliable information for a precise analysis and to develop formulations to use for a long-term wind power investment in order to provide an investor with the assessment of the potential investment. The economic analysis consists of simulating inputs and outputs of the power generating company and manufacturing facilities so that the interaction of all agents can be observed. The power generating company economically dispatches available generating units to meet the load at particular times and locations in the transmission grid. The dispatch of the generating units is achieved by solving a linear program formulation called the optimal power flow (OPF) model. Locational marginal prices are obtained from the dual variables of the linear program's constraints. In the investment economic analysis, forecasted prices are used by the manufacturing facilities to schedule their operations. After the manufacturing facilities implement their schedules, the power generating company disptaches the generating units using the OPF model, and real-time prices are obtained. The investment economic analysis integrates the manufacturer's operations and the electricity market.

The remainder of this dissertation is organized as follows: In chapter 2, some important background on wind power, demand response programs, and energy pricing as well as a review of related research are given. In chapter 3, model assumptions are described and the operating models are formulated. Chapter 4 describes comparison analysis of the system operating models and constructs correction models. Chapter 5 describes and formulates wind energy's economic analysis. Chapter 6 provides numerical results and the economic analysis. Chapter 7 summarizes the research study, gives conclusions, and recommends future research.

CHAPTER 2

REVIEW OF LITERATURE AND BACKGROUND

In this section, the literature related to this research is discussed. Some background on the wind technology and modeling approaches are also discussed in the background section.

2.1 Literature Review

Electricity is generated from wind by converting kinetic energy via a wind turbine. While there is no cost to using wind, wind is a highly erratic source of energy, and wind speed is difficult to verify. Therefore, the issues that impact wind power as an energy source will be discussed under separate subsections. Firstly, wind speed forecasting and modeling are described in the Wind Speed Forecast section of this review. Secondly, there are two primary sides to the electricity market, producers and consumers or suppliers and demanders. The Economic Dispatch (ED) Problem is used to resolve questions relating to the demand and supply of electricity. The modeling and solution approaches of ED are described in the Economic Dispatch Problem section. Last but not least, investment in wind power is growing rapidly, and there is now serious interest in connecting wind power to the power grid. Individual cases of combining wind power with a fossil fuel power plant are discussed in the Conventional Thermal Power Generator in Conjunction with Wind Power Generator section.

2.1.1Wind Speed Forecast

As its name implies, a wind turbine or wind power generator generates electricity using wind. Wind speed drives the blade and the mechanism inside a wind turbine, thereby activating a generator motor and rotor, thus producing electricity. This is a simple process, but dealing with wind speed is not a straightforward task. Because of the unique characteristics of wind speed, it is difficult to verify wind speed efficiently. Many researchers have studied wind speed and developed models for forecasting it. Wind behavior expresses a great degree of randomness; however, existing statistical methods are able to predict wind speed behavior. The following are some important techniques for forecasting wind speed.

Time series models to simulate and forecast wind speed and wind power have been used by Brown, Katz, and Murphy [8]. The approach was applied to a small set of hourly wind speed data form the Pacific Northwest. Autocorrelation, non-Gaussian distribution, and diurnal nonstationarity were used to fit an autoregressive process to the wind speed data. The researchers transformed these data and made the distribution approximately Gaussian and standardized to remove diuarnal nonstationarity. Monte Carlo simulation was used to forecast wind speed using parameters based on Gaussian distribution. However, even though simulation is a potential tool in forecasting wind speed, statistics are equally important.

Dealing with the high penetration of wind power in the electricity system is challenging. A grid operator has to deal with the intermittency of wind because a wind farm output relies mainly on the wind speed. Also, the operating costs for the electric system could increase due to unexpected variation of a wind farm’s output. Siderators and Hatziargyriou [9] have proposed an advanced statistical method for wind power forecasting. Their method is intended to be used to reduce the inaccuracy of wind prediction. They use artificial intelligence and fuzzy logic techniques to forecast wind power. The result is based on numerical weather predictions (NWPs). Furthermore, they developed three models: the preliminary wind power prediction model, a model that provides a fuzzy index of the reliability of the numerical weather predictions, and the final wind prediction model. The results show that the method is good for an offshore wind farm and can be applied effectively for operational planning up to 48 hours ahead.

Contaxis and Kabouris [10] proposed short term scheduling in a wind/diesel autonomous energy system. They divided their work into two main parts: the short term forecasting of loads and wind speeds and the short term unit commitment. They used the autoregressive moving average (ARMA) models for loads and wind speed prediction. Loads and wind speed were assumed to be random variables with known probability distributions. A seasonal Daily-Weekly ARMA (3.1) and a non-seasonal AR (3) were used for load demand prediction and wind speed prediction, respectively. The former algorithm resulted in less than 3% prediction error while the latter algorithm resulted in 15% prediction error.

Patel [11] stated that wind patterns generally repeat over the period of one year. The wind site is usually described by the speed data averaged over the calendar months. Patel also stated that wind speed can be described by a probability distribution function; wind speed is mostly fitted to a Weibull distribution.

Chan *et al*. [12] proposed operational requirements for utilities with wind power generation. They proposed the computational method and the necessary wind speed, a probabilistic framework to the load-following, the operating-reserve and the unloadable-generation requirements for a utility with one or more spatially dispersed wind turbine clusters. They compared the accuracy of the model to an actual site located in Clayton, New Mexico.

2.1.2 Economic Dispatch Problem

The process of an economic dispatch (ED) is to allocate the electricity generated by power generators so that this electricity will meet both economically and fully the demand at a particular area and during a particular period. Several methods have been proposed to deal with this problem, including the following:

Talukda and Wu [13] reviewed the optimal power flow method and discussed the different computer-aided methodologies used in this procedure.

Megahed *et al*. [14] proposed a method for solving the economic dispatching problem by converting it from a constrained nonlinear programming problem to a sequence of constrained linear programming problems. Results showed that this method provided a good rate of convergence and a small number of iterations.

Irving *et al*. [15] proposed a method to solve the economic dispatch in large-scale power systems using a dual revised Simplex method but relaxed the constraints in order to attain a feasible solution. According to the authors, the algorithm was computationally efficient and applicable to online dispatch for large-scale systems.

Mota-Palomino and Quintana [16] used a piecewise differentiable penalty function minimization to solve constrained economic dispatch problems. Primal and dual algorithms were used to develop the solution approach. Both algorithms are based on the revised simplex method.

Waight *et al*. [17] reformulated general dispatch with reserve margin constraints as linear programming. The new structure is decomposed into smaller linear programming subproblems and uses the Dantzig-Wolfe algorithm to resolve the dispatch with the reserve margin constraint problem.

Maria and Findlay [18] combined the Newton approach and linear programming to solve the optimal power flow problem. According to the authors, a technique based on LP is used to identify the binding inequalities. All binding constraints are enforced using Lagrange multipliers, resulting in a faster solution.

Lee *et al*. [19] decomposed the problem into the real power optimization problem (P-problem) and the reactive power optimization problem (Q-problem) and used the gradient projection method (GPM) to solve them. The authors used the load-flow procedure to make a fine adjustment on the results of P-and Q-optimization procedures and used the Newton-Raphson method to obtain the optimal solution.

Another technique that is extensively used to solve the optimal power flow problems is the nonlinear programming approach. It is represented as follows:

Contaxis *et al*. [20] formulated the optimal power flow problem as a non-linear constrained problem. The problem was then decomposed into a real subproblem and a reactive subproblem. Then, the two subproblems were transformed into a quadratic programming problem and solved.

Burchett *et al*. [21] proposed a method to solve a problem involving a large scale power system with 500 or more buses. The technique is to transform the original problem into a sequence of linearly constrained subproblems using an augmented Lagrangian type objective function. The subproblems are solved using a set of descent directions, including quasi-Newton, conjugate directions, and steepest descent.

A method for solving the optimal power flow problem in real time is explained by Bacher and Meeteren [22]. The problem is separated into two stages. The first stage is full optimal power flow in non-time critical mode. The second stage is referred to as constrained economic dispatch and solved using the quadratic programming technique.

Talukda *et al.* [23] introduced a new algorithm to solve the small optimal power flow problem. According to the authors, the Han-Powell algorithm proves to be fast and robust.

Su and Chiou [24] adapted the Hopfield method for solving the economic dispatch problems. This method normally uses a linear input-output model for neurons. According to the authors, instead of iterations for solving the problem, the Hopfield method computes the created formulation directly, resulting in excellent performance and proving superior to other methods in many respects.

Lee *et al.* [25] used a transportation method to solve the economic dispatch problem. The method is based on two transportation techniques. The minimum cost flow method is used to determine the initial optimum. The Minty algorithm is used to find the approximation of the generator and transmission line incremental cost to find the optimum.

2.1.3 Conventional Thermal Power Generator Incorporated with Wind Power Generator

Recently, wind power generators have been used in conjunction with existing thermal power plants. Many researchers have been studying the effect of the generation of wind power in the competitive markets. In addition, wind power will help the market to reduce the wholesale price of electricity as well as to lower carbon emissions in the power network. The following describe some of these studies:

Galloway *et al.* [26] developed the management strategies to maximize the revenues the generator received while minimizing financial risk the generator is exposed to because of the characteristic uncertainty of wind speed.

Many wind producers participate in a liberalized electricity market and therefore most are penalized in relation to the regular cost due to the inaccuracy of wind forecasts. Pinson *et al.* [27] developed an application based on predictive distributions, and this can be considered the basis for advanced strategies for market participation. These can help the producer to reduce penalties and maximize revenues.

Due to the inaccuracy of wind forecasts, wind producers tend to beat commercial risk through imbalance costs when advance contracting. To deal with this problem, Bathurst *et al.* [28] developed a method based on Markov Probabilities for a wind farm, resulting in a reduction of the imbalance costs.

Pinson *et al.* [29] used a statistical model called Armines Wind Power Prediction System (AWPPS) to maximize benefits from wind power included in the electricity market. Also, according to the authors, this technique minimized the financial risk and penalties due to the imbalance.

In some cases, strategies have been developed for the wind producer's side. Holttinen [30] used the Wind Power Prediction Tool (WPPT) developed by the Technical University of Denmark to deal with the uncertainty of wind participation in the market. The results revealed that prediction for a shorter period is far superior than prediction for a longer period.

Usaola and Angarita [31] used the tool called SIPREOLIO to perform wind prediction and included the result in their model. According to the authors, the result improved the maximization of revenues and the minimization of losses due to imbalance costs.

Another technique, stochastic programming, is used to minimize imbalance cost with wind participants. Matevosyan and Soder [32] developed a model for optimal wind power production bids for the short-term power market. The result from the model showed that an imbalance cost minimizing bidding strategy generally results in higher or equal profits than a strategy where a player bids based on the forecasted wind power production and then pays imbalance costs.

2.2 Background

In this section, the background of the power network system and wind power is described. In general, an electricity network involves producers and consumers. Under real-time pricing, producers supply electricity as well as determine energy prices at a particular time and location to consumers. Consumers respond to the price of energy via their electricity consumption behavior which varies according to the fluctuations in energy prices. Some large customers, such as manufacturing plants, take certain actions to take advantage of real-time pricing in order to cut their energy costs. One such action is to schedule their hours of operation to ensure paying minimal electricity cost while maintaining steady production. Another action is for manufacturing plants to have their own self-generators which supply part or all of their need for power consumption. The self-generators come in two main types: those fueled by fossil fuels and those fueled by renewable fuels.

2.2.1 Renewable Energies

There are numerous materials that can be used to replace conventional energy. One of those is renewable energy. Renewable energies are obtained from natural resources. Those sources of energy take many forms, such as geothermal heat, tide, rain, wind, and sunlight, all of which are naturally replenished. Nowadays, both sunlight and wind are used to produce electricity in forms of solar cell and wind turbine. However, in this research, wind power is emphasized and more detail will be discussed in a following section.

2.2.1.1 Wind Power

Wind is one of the renewable energy sources that can be used in many fields. Sailors have long taken advantage of wind energy to propel their ships. In agriculture, famers use wind energy to drive pumps for pumping or draining water in their farms. One of the advantages of wind energy is that it does not produce air or water pollution [33]. In addition, there is no cost for using it. To use wind power, wind characteristics and its operation must be scrutinized because wind power is a vastly variable energy production source and it is non-dispatchable.

Today, wind energy is extensively used in electricity generation. By the end of 2009, 159.2 GW of wind-powered generators had been installed [34]. Wind energy is converted into electricity via a wind turbine, and this conversion is generally called wind electric power. A wind turbine is a rotating machine which converts kinetic energy in wind via the mechanical energy inside the turbine into electricity as shown in Figure 2.1. Wind electric power can be calculated as

$$P = \frac{1}{2}\alpha\rho\pi r^2 v^3 \tag{2.1}$$

where P is power in watts, α is an efficiency factor determined by the design of the turbine, ρ is the mass density of air in $\frac{kg}{m^3}$, r is the radius of the wind turbine in meters, and v is the velocity of air in $\frac{m}{s}$. The basic structure inside a wind turbine is shown in Figure 2.1.

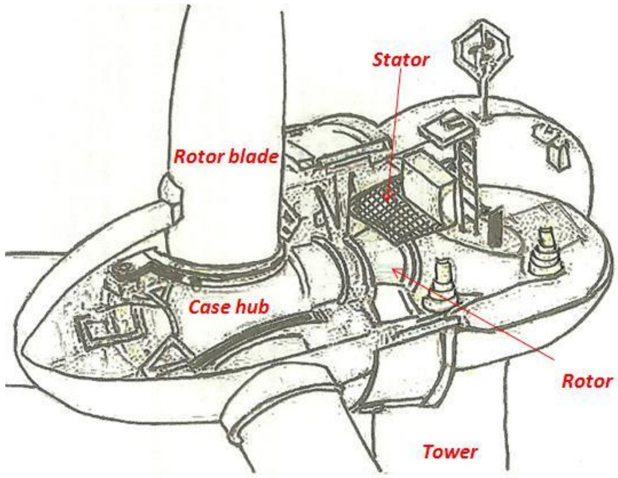

Figure 2.1: Basic Structure inside a Wind Turbine

A wind turbine range can be classified into two categories: small scale and large scale. Small scale ranges from 1 kilowatt to 50 kilowatts [1] while large scale ranges from 250 kilowatts to 7.58 megawatts [35]. Wind speeds as low as 2 meters per second can successfully drive a well-constructed wind turbine. However, a wind turbine has some limitations due to its specifications. Generally, a wind turbine cannot work when wind speed is lower than the cut-in wind speed. Furthermore, when wind speed reaches cut-out wind speed, a wind turbine will be automatically shut down in order to prevent damage to the machine. The wind speed operating curve is shown in Figure 2.2.

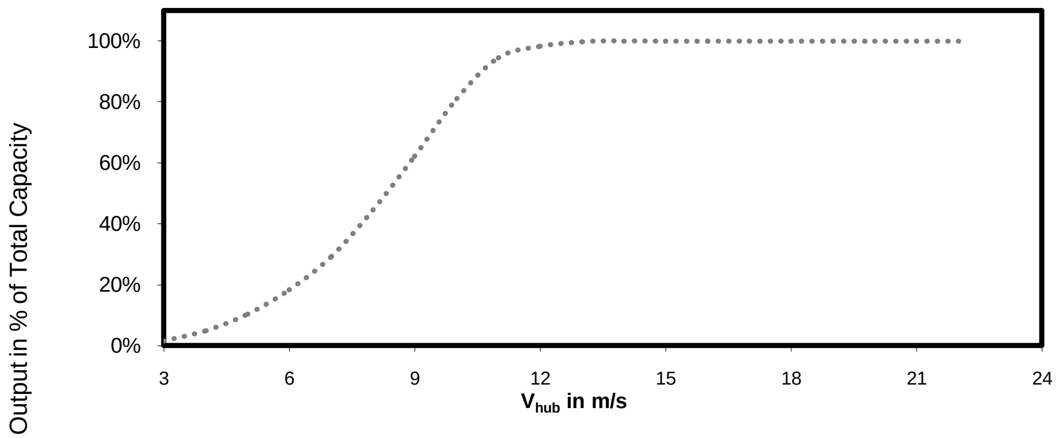

Figure 2.2: Cut-in and Cut-out Wind Speed

In some areas, more than one wind turbine is installed and this is called "a wind farm." A wind farm is a group of wind turbines in the same location for generating electricity. There are three types of wind farms: onshore, nearshore, and offshore. An onshore wind farm is generally located three kilometers or more inland from the shoreline [36]. A nearshore wind farm is situated within three kilometers of a shoreline and within ten kilometers of land [36]. An offshore wind farm is found at ten kilometers or more from land [36].

Electricity generated by a wind farm ranges from 108 to 780 megawatts. The Roscoe Wind Farm, located in Texas, United States, is currently the world's largest wind farm [37]. At the end of 2009, the total capacity of wind power in the United States was equivalent to that of three large nuclear power plants [38].

2.2.2 Demand Response Programs

Demand response in electricity grids is a device used to supervise the electricity consumption of consumers in response to supply conditions. In general, demand response is an implement used to encourage customers to reduce the load during particular period, thus leading to a reduction in the peak load for electricity. Two types of demand response are in use: emergency and economic demand responses. The former is used to avoid outages and the latter is mainly used to control the daily peak. According to the U.S. load profile [6], peak load will occur in particular periods during the year, and the Independent System Operator (ISO) will inevitably have to start peaking generation units to allocate the electricity to meet the load. Typically, those costly units are turned off during this time since they generate high energy prices within the system. The record [6] shows that 15% of generation capacity in PJM territory operated 1.1% or fewer hours in 2006.

The demand response program has been established to avoid peak demand. If peak demand occurs, the power company will lose profits since they charge a flat rate to the customers, while peaking generation units usually generate higher marginal cost. For this reason, a new tool must be implemented so that the power companies could reduce situations requiring them to turn on expensive generation units, thus allowing them to maintain profits. This need led to the establishment of smart grid technology.

2.2.2.1 Smart Grid Technology

The main purpose of the smart grid is to upgrade the 20th century power grid. A smart grid delivers electricity from producers to end users using two-way digital technology to control appliances at consumers' homes or machinery at manufacturing plants to save costs and reduce energy. A smart grid consists of a smart meter, an intelligent monitoring system that is used to keep track of electricity flow in the entire network.

Using this modernized technology, consumer behavior can be changed with respect to electricity usage. For instance, since the central power generators broadcast power via smart meter, the consumers are informed of the real-time price and, therefore, the consumers can opt to turn off their appliances at the time the energy price is comparatively high and turn on their appliances in the hours during which the energy price has dropped. In this way, their total power consumption remains unchanged, but they save by using less expensive electricity. The conceptual smart grid technology is represented in Figure 2.3.

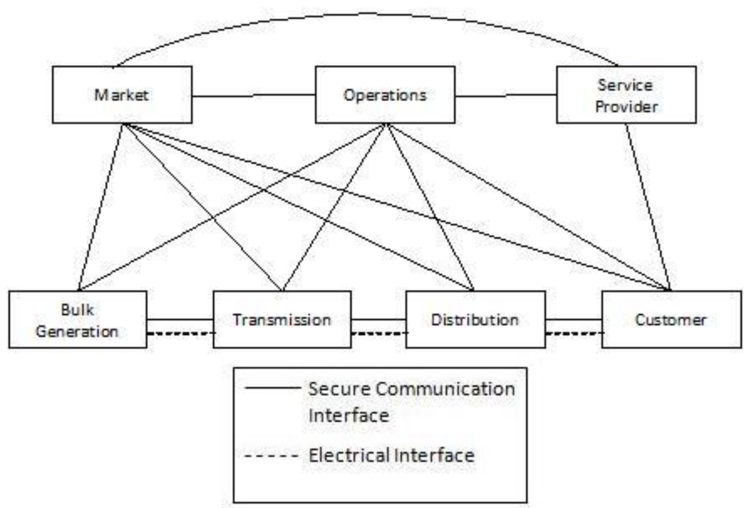

Figure 2.3: Smart Grid Technology

2.2.3 Locational Marginal Pricing

When a specific amount of committed electricity and an offer price have been submitted to the independent system operator (ISO), the ISO allocates that amount of electricity to meet the demand and, at the same time, the system energy price is established. However, since several nodes are represented, there are also different nodal prices when transmission congestion cost is taken into account. With real-time pricing, the nodal prices, or location marginal prices (LMP), reflect the hourly marginal cost of generating electricity, and the ISO determines these LMPs to offer to the consumers at a particular period and location.

2.2.4 A Procedure for Selling Wind Electric Power

The main objective of this section is to provide some suggestions to wind power investors on how they will do with their investment. There are three types of wind power investors: all use, part use, and all sell. An example of the first type of investors is manufacturing facilities since they use all the wind electric power within their plants. For this reason, they have nothing to do with the selling procedure. The second type of investors invests in wind power to supply electricity in their plants but sells the surplus amount to the power grid. The third type of investor could be an independent investor, also referred to as a third party, or a power company considering developing a wind farm as their cheapest generator. They invest in a wind farm so that they can sell all wind electric power.

The process detailed here might not include complete information, but it will at least give some ideas to future wind electric power investors as to how to begin on the investment. The procedure for selling wind electric power will be discussed later and an example will be given.

Generally for a power generating company, when wind electric power has been generated, all electricity generated by wind will be dispatched because wind-generated electricity is the cheapest generation unit. Because the power company owns the wind power generators and has ready access to the grid the company should have no problem connecting these wind generators to the electricity grid.

However, if the wind farm is owned by a third party, how will the process of selling wind power to the grid be done? The following is an example of what a wind power investor could do.

Entergy, a Louisiana based power supply company, offers customers who generate electricity using renewable energy the opportunity to sell their surplus electricity to the company via Net Meter. Net Metering is available for resident and commercial generation facilities. Those customers who have not connected their generation facilities to the grid yet will send their surplus electricity to Entergy. In New Orleans Net Metering, the amount of electricity generated by a customer will be sent to the grid and this will compensate for the amount that the company sells to a customer. If the customers can produce and send more electricity than they buy, the offset will be credited to the customer for following month. However, the company is required to supply a meter with the capability of recording two-way electrical flows. Therefore, the customers need to either complete or submit an application form or request the vendor of the equipment help fill out the application [39].

2.2.5 Optimization Models

Since this dissertation's research involves several models, the solution of one model will also be the solution of another model. Some important optimization models will be discussed through this section as follows:

2.2.5.1 Nonlinear Programming

The objective function of this problem is nonlinear whereas the constraints are strictly linear. The applications of nonlinear programming are comprehensively used in many areas such as business, industry, and military as well as government organizations. The general model can be represented as [40]:

Minimize $f(\boldsymbol{x})$ (2.1)

subject to

$g_i(\boldsymbol{x}) \leq 0 \qquad i = 1..m$ (2.2)

$h_i(\boldsymbol{x}) = 0 \qquad i = 1..l$ (2.3)

$\boldsymbol{x} \in X$ (2.4)

The equation (2.2) is the set of inequality constraint while the equation (2.3) is the set of equality constraint. The parameter X is a subset of *n*-dimensional Euclidean space.

2.2.5.2 Bilevel Programming

Bilevel programming is classified as an optimization problem where a subset of variables is constrained to lie in the optimal set of an auxiliary mathematical program [41]. In other words, one optimization problem is embedded in another optimization problem. The practical applications of bilevel programming appear in many fields such as economics, engineering, and transportation. The general model of bilevel programming can be represented as [41]:

$\min_x \max_y \; f(x, y)$ (2.5)

subject to

$$(x, y) \in X \tag{2.6}$$

$$y \in S(x) \tag{2.7}$$

where $S(x)$ is the solution set of a mathematical program parameterized in the vector x that is

$$S(x) = \text{arg min}_y \, g(x, y) \tag{2.8}$$

subject to

$$(x, y) \in Y \tag{2.9}$$

(2.7) is embedded in (2.5) and (2.6) and it is implied that the optimization of (2.7) will also be the optimization of (2.5).

2.2.5.3 The Karush-Kuhn-Tucker Condition

In order to obtain an equilibrium condition, first order conditions must be applied. The procedure for this is to transform a constrained optimization problem into first order KKT conditions. Given the following maximum constrained optimization problem:

$$\text{Maximize } F(x, y) \tag{2.10}$$

subject to

$$G(x, y) = 0 \tag{2.11}$$

$$H(x, y) \leq 0 \tag{2.12}$$

$$x \geq 0 \tag{2.13}$$

Let λ and μ be the dual variables associated with equality function (2.11) and inequality function (2.12), respectively. Using complementarity and equality constraints, the KKT conditions can be written as follows:

$$\text{for } x: \frac{\partial F}{\partial x} - \lambda \frac{\partial G}{\partial x} - \mu \frac{\partial H}{\partial x} \leq 0, x \geq 0, x\left(\frac{\partial F}{\partial x} - \lambda \frac{\partial G}{\partial x} - \mu \frac{\partial H}{\partial x}\right) = 0 \tag{2.14}$$

for y: $\frac{\partial F}{\partial y} - \lambda \frac{\partial G}{\partial y} - \mu \frac{\partial H}{\partial y} = 0$ (2.15)

for λ: $G(x, y) = 0$ (2.16)

for μ: $H(x, y) \leq 0, \mu \geq 0, \mu H(x, y) = 0$

2.2.5.4 Mathematical Programs with Complementarity Constraints

In this case, complementarity problems or variation inequalities serve as the constraints of the optimization problem [42]. This means one linear program problem is translated into complementarity constraints using the first order KKT conditions. The general model is represented as follows [43]:

Minimize $\tilde{f}(\mathrm{x})$ (2.17)

subject to

$c(x) \geq 0$ (2.18)

$0 \leq x_1 \perp x_2 \geq 0$ (2.19)

where

$x = (x_0, x_1, x_2)$

$\perp =$ complementarity operator

CHAPTER 3

SYSTEM OPERATING MODEL FORMULATION AND ASSUMPTIONS

In this chapter, two System Operating (SO) Models (SO-A and SO-B) are developed to represent the interaction between a manufacturing facility's energy usage and a power network system. The SO models are intended to be used by a manufacturing facility to make daily operating decisions regarding power consumption at real-time market prices. Having two SO models allows comparison of the trade-off between model formulation and solution method efficiency. The models consist of two interrelated linear programming (LP) formulations. One LP formulation, called the Manufacturing (MFG) model, represents the operation of a manufacturing facility. The other LP formulation, called the Optimal Power flow (OPF) model, models the power system. The facility uses the OPF model to simulate how the power generating company dispatches its generating units and determines energy prices.

The MFG and OPF models are connected by the dual prices of the OPF model's load balance constraints and by the production levels (decision variables) of the MFG model. The manufacturing facility perceives the dual prices of the OPF model as energy costs. These costs are used to make decisions on production levels, which determine the energy load of the manufacturing facility. The power generating company uses the manufacturing facility's load to make the dispatch decisions for its generating units.

One difference between models SO-A and SO-B is that the former uses the market prices on the same day that the manufacturing facility decides on the production levels. The latter uses the market prices on the previous day to make the same operating decisions. Another difference is how they model the presence of additional manufacturing facilities. Model SO-A includes the loads of additional facilities by assuming that the facilities follow the same operating pattern as the manufacturing facility that is solving the MFG model. The reason for this assumption is to facilitate the solution of the resulting formulation. Model SO-B, on the other hand, explicitly includes the operation of all facilities. The load of residential consumers is represented by aggregated load profiles, which are assumed to be known.

3.1 Manufacturing (MFG) Model

In this research, it is assumed that the manufacturing facility has a daily production target that must be achieved. As a result, the facility's revenue is constant and the operating cost can be changed through scheduling decisions for the facility's operations. The manufacturing facility is assumed to be a bulk material manufacturing facility. Bulk materials such as rice, corn, cement, and so forth, have their respective units of volume: kilogram, ton, and etc. An example of this type of manufacturing facility would be a raw material grinding plant in a cement manufacturing plant. Raw materials, i.e. limestone, shale, and iron ore, are mixed and ground in a raw mill. The finished product, called "raw meal," is then stored in a silo and is charged by inventory cost. The raw meal is classified as a bulk material, and its unit of volume is a ton. This type of manufacturing facility has a daily production target, and when the target has been achieved, the facility is stopped. According to its total hourly capacity, the facility would run a certain number of hours to meet the target.

If the manufacturing facility is charged different energy prices during off-peak and peak hours, the facility operates at full capacity during off-peak hours and stops during peak hours, saving on energy costs. However, the facility may have to change its previous schedule to respond to the fluctuations of energy prices. In this case, the goal of the manufacturing plant is to minimize its daily energy and inventory costs and still meet the target demand. Any other costs such as labor, material, and maintenance are not included in the minimization function because these costs remain unchanged. In general, manufacturing facilities run 24 hours a day. Maintenance technicians work on a shift schedule and they stand by for 24 hours. Therefore, there would be no additional cost if they are scheduled to do maintenance at any other hour. For material cost, since the facilities produce the same production target, the material cost will be unchanged as well.

The manufacturing facility has two sets of decisions to make in order to meet its daily production target while minimizing its operating costs. One is to decide the hourly inventory level and the other is to decide the hourly production level. The inventory level at hour t is denoted by the decision variable i_t while the production level at hour t is denoted by u_t. The decision variable u_t is a number in the interval [0, 1] and represents the fraction of the hourly maximum capacity (CP) of the manufacturing facility. The total energy consumed when the facility is producing at CP is E in megawatt hours (MWh). The price that the manufacturing facility pays for the consumed energy at hour t is the Locational Marginal Price (LMP) at the node location of the manufacturing facility on the power grid at that hour. Therefore, the "price" variable P_t is the LMP at the node where the manufacturing facility is located.

The facility's production schedule is adjusted according to energy prices, ensuring that hourly production mostly runs at relatively low energy prices while meeting daily production goals. The inventory level relates directly to the production schedule. When a machine is scheduled to operate, the inventory is built up. Therefore, the facility's objective is to minimize inventory and energy costs. The MFG model is as follows:

$$\text{Min } F = \sum_t \{I^{cost} \cdot i_t + P_t \cdot E \cdot u_t\} \tag{3.1}$$

subject to

initial inventory constraint:

$$i_1 = I_0 + CP \cdot u_1 \tag{3.2}$$

production balance constraints:

$$i_t = i_{t-1} + CP \cdot u_t \qquad t = 2..T \tag{3.3}$$

total demand constraint:

$$i_T = D \tag{3.4}$$

production schedule constraints:

$$0 \leq u_t \leq 1 \qquad t = 1..T \tag{3.5}$$

nonnegativity constraints:

$$i_t \geq 0 \qquad t = 1..T \tag{3.6}$$

In this research, the manufacturing facility is assumed to be located at bus M. The index M in P_t is omitted for the sake of simplicity.

There are five types of constraints. The first constraint (3.2) represents the inventory level during the first period ($t = 1$). The inventory level at the first period is equal to the production level during the first period plus the initial inventory level denoted by I_0. The second set of constraints (3.3) is the production level balance during each period where $t = 2..T$. These constraints ensure that the previous inventory level and the current production level are equivalent to the current inventory level. The third constraint (3.4) is the inventory level at the final period. This constraint sets the final inventory level to meet the total daily demand target (D). The fourth set of constraints (3.5) corresponds to the production level u_t. Finally, the fifth set of constraints (3.6) corresponds to the inventory levels which are simply restricted to be nonnegative.

3.2 The Optimal Power Flow (OPF) Model

In this model, the power generating company minimizes its generation cost objective while supplying electricity to meet loads at particular periods and locations. The DC power flow model [44] is used to represent the power network. Since the main goal of this research is to evaluate wind power investment, a wind farm is included in the model. The OPF model is as follows:

For $t = 1..T$

$$\text{Min } z_t = \sum_k C_k \cdot g_{k,t} \tag{3.7}$$

subject to

load balance constraint:

$$\sum_k \left(g_{k,t} + W_{k,t}\right) = \sum_k L_{k,t} \qquad (\lambda_t) \tag{3.8}$$

power flow constraints:

$$\sum_k A_j^k \cdot \left(g_{k,t} - L_{k,t} + W_{k,t}\right) \leq F_{j,t}^{\max} \qquad \left(\mu_{j,t}^{+}\right)\ j = 1..J \tag{3.9}$$

$$\sum_k A_j^k \cdot \left(g_{k,t} - L_{k,t} + W_{k,t}\right) \geq -F_{j,t}^{\max} \qquad \left(\mu_{j,t}^{-}\right)\ j = 1..J \tag{3.10}$$

generation capacity constraint:

$$G_{k,t}^{\min} \leq g_{k,t} \leq G_{k,t}^{\max} \qquad \left(\beta_{k,t}^{+/-}\right)\ k = 1..K \tag{3.11}$$

wind power constraint:

$$0 \leq W_{k,t} \leq W_{k,t}^{max} \qquad k = 1..K \tag{3.12}$$

The objective function (3.7) minimizes the total generation cost for all generators on the power network at all periods. The load balance constraint (3.8) implies that the dispatched generating units plus the wind power should meet the total load at every location and time. Constraints (3.9) and (3.10) are the upper and lower bounds of the power flows in the network, respectively. The constraints are described as the difference between the amount of electricity dispatched (from conventional generators and wind power) and the amount of load multiplied by the Power Transmission Distribution Factors (PTDFs), which should be less than the maximum power flow on the corresponding transmission line. Constraint (3.11) is the capacity limits for each generator and constraint (3.12) is the upper bound for the wind power available at a particular period.

The variables given in parenthesis correspond to the dual variables of the related constraints. For instance, the dual variable; λ_t, of constraint (3.8) represents the system energy price. This price is used to calculate the LMPs. The hourly LMPs at node $k = 1..K$ can be calculated using the following equation.

$$P_{k,t} = \lambda_t + \sum_j \left(A_j^k \cdot \mu_{j,t}^{+} + A_j^k \cdot \mu_{j,t}^{-}\right) \tag{3.13}$$

where λ_t is the dual price of the load balance constraint at bus k and time t, $\mu_{j,t}^{+/-}$ is the dual price of the line j at time t, while A_j^k is the PTDF at line j from bus k to a hub. The $P_{k,t}$ is the energy price at time t and varies depending on the node at which the manufacturing facility is located. In (3.1) the value of P_t is $P_{M,t}$.

3.3 SO-A Model

In this section, the interdependence of MFG and OPF is described as a bilevel program formulation. This formulation connects both models by sharing their solutions. That is, the solution of MFG is the input to OPF and vice versa. MFG requires the dual variables (prices) of the OPF model, which in turn requires the production levels (loads) of the MFG model. Assuming that the manufacturing facility is located at node M, the SO-A model is as follows:

$$\text{Min } F = \sum_t \left\{ I^{cost} \cdot i_t + [\lambda_t + \sum_{j,M} (A_j^M \cdot \mu_{j,t}^{+} + A_j^M \cdot \mu_{j,t}^{-})] \cdot (E \cdot u_t) \right\} \tag{3.14}$$

subject to

initial inventory constraint:

$$i_1 = I_0 + CP \cdot u_1 \tag{3.15}$$

production balance constraints:

$$i_t = i_{t-1} + CP \cdot u_t \qquad t = 2..T \tag{3.16}$$

total demand constraint:

$$i_T = D \tag{3.17}$$

production schedule constraints:

$$0 \leq u_t \leq 1 \qquad t = 1..T \tag{3.18}$$

nonnegativity constraint:

$$i_t \geq 0 \qquad t = 1..T \tag{3.19}$$

the optimal power flow model constraints:

For $t = 1..T$

$$\text{Min } z_t = \sum_k C_k \cdot g_{k,t} \tag{3.20}$$

subject to

load balance constraints:

$$\sum_k g_{k,t} = \sum_k L_{k,t} - W_{k,t} \qquad (\lambda_t) \tag{3.21}$$

power flow constraints:

$$\sum_k A_j^k \cdot \left(g_{k,t} - L_{k,t} + W_{k,t}\right) \leq F_{j,t}^{\max} \qquad \left(\mu_{j,t}^{+}\right)\ j = 1..J \tag{3.22}$$

$$\sum_k A_j^k \cdot \left(g_{k,t} - L_{k,t} + W_{k,t}\right) \geq -F_{j,t}^{\max} \qquad \left(\mu_{j,t}^{-}\right)\ j = 1..J \tag{3.23}$$

generation capacity constraints:

$$G_{k,t}^{\min} \leq g_{k,t} \leq G_{k,t}^{\max} \qquad \left(\beta_{k,t}\right) \quad k = 1..K \tag{3.24}$$

wind power constraints:

$$0 \leq W_{k,t} \leq W_{k,t}^{max} \qquad k = 1..K \tag{3.25}$$

Load equations:

$$L_{k,t} = nominal\, L_{k,t} + E_k \cdot u_t \quad k = 1..K, t = 1..T \tag{3.26}$$

Notice that in (3.14) the LMP has been expanded by using the dual variables in (3.21) – (3.23). The remaining equations in this model are identical to those in sections 3.1 and 3.2 except for the load equation (3.26). At bus k, the total load is the nominal load plus the load from the operating schedule of facility k. Constraint (3.26) implies that all manufacturing facilities follow the same production pattern as the manufacturing facility that solves the MFG model. The nominal load is the load of residential aggregated consumers.

3.3.1 Solution approach for the SO-A Model

To solve the bilevel programming model described in section 3.3, first order KKT conditions of the OPF model are used to translate the OPF model into a set of complementarity constraints for the MFG. The dual variables λ_t and $\mu_{j,t}^{+/-}$ become decision variables for the MFG model and the objective function becomes a quadratic function. Consequently, the transformed SO-A model is a quadratic program with complementarity constraints and it is equivalently rewritten as

$$\text{Min } F = \sum_t \left\{ I^{cost} \cdot i_t + [\lambda_t + \sum_{j,M} (A_j^M \cdot \mu_{j,t}^+ + A_j^M \cdot \mu_{j,t}^-)] \cdot (E \cdot u_t) \right\} \tag{3.27}$$

subject to

initial inventory constraint:

$$i_1 = I_0 + CP \cdot u_1 \tag{3.28}$$

production balance constraints:

$$i_t = i_{t-1} + CP \cdot u_t \qquad t = 2..T \tag{3.29}$$

total demand constraint:

$$i_T = D \tag{3.30}$$

production schedule constraints:

$$0 \leq u_t \leq 1 \qquad t = 1..T \tag{3.31}$$

nonnegativity of inventory level constraints:

$$i_t \geq 0 \qquad t = 1..T \tag{3.32}$$

For $t = 1..T$

optimal power flow complementarity constraints:

$$g_{k,t}: -C_k - \lambda_t - \sum_j (-\mu_{j,t}^- \cdot A_j^k + \mu_{j,t}^+ \cdot A_j^k) - \beta_{k,t} \leq 0 \quad k = 1..K \tag{3.33}$$

$$g_{k,t} \cdot \left\{ -C_k - \lambda_t - \sum_j (\mu_{j,t}^+ \cdot A_j^k - \mu_{j,t}^- \cdot A_j^k) - \beta_{k,t} \right\} = 0 \quad k = 1..K \tag{3.34}$$

$$\lambda_t : \sum_t \left(g_{k,t} - L_{k,t} + W_{k,t} \right) = 0 \tag{3.35}$$

$$-F_{j,t}^{max} - \sum_k A_j^k \cdot \left(g_{k,t} - L_{k,t} + W_{k,t} \right) \leq 0 \quad j = 1..J \tag{3.36}$$

$$\mu_{j,t}^{-} \cdot \left(-F_{j,t}^{max} - \sum_k A_j^k \cdot \left(g_{k,t} - L_{k,t} + W_{k,t} \right) \right) = 0 \tag{3.37}$$

$$\sum_k A_j^k \cdot \left(g_{k,t} - L_{k,t} + W_{k,t} \right) - F_{j,t}^{max} \leq 0 \quad j = 1..J \tag{3.38}$$

$$\mu_{j,t}^{+} \cdot \left(\sum_k A_j^k \cdot \left(g_{k,t} - L_{k,t} + W_{k,t} \right) - F_{j,t}^{max} \right) = 0 \tag{3.39}$$

$$g_{k,t} - G_{k,t}^{max} \leq 0 \qquad k = 1..K \tag{3.40}$$

$$\beta_{k,t} \cdot \left(g_{k,t} - G_{k,t}^{max} \right) = 0 \qquad k = 1..K \tag{3.41}$$

nonnegativity of dual variables constraints:

$$\mu_{j,t}^{+} \geq 0 \qquad j = 1..J \tag{3.42}$$

$$\mu_{j,t}^{-} \geq 0 \qquad j = 1..J \tag{3.43}$$

$$\beta_{k,t} \geq 0 \qquad j = 1..J \tag{3.44}$$

Load equations:

$$L_{k,t} = nominal\, L_{k,t} + E_k \cdot u_t \quad k = 1..K, t = 1..T \tag{3.45}$$

The model has two types of constraints: linear (3.28)-(3.30) and complementarity (3.33)-(3.41). The linear constraints are the manufacturing constraints while the complementarity constraints are from the OPF model.

In the SO-A model, the manufacturing facility that solves the model is called “main facility” and sees other manufacturing facilities as additional loads, which act as followers since they are assumed to execute the main facility’s operating schedule. The advantage of this model is that the main facility uses real-time energy prices from the same day because the energy prices and production levels are solved simultaneously. Figure 3.1 illustrates the interaction between the MFG and OPF models. In the figure, the manufacturing facility plans its operating schedule right before the operating day starts. On day D, the SO-A model is solved using manufacturing facility data, power plant data, and load profile. The manufacturing data are inventory cost and daily production target, while the power plant data consist of generation cost, generation capacity, PTDFs, and maximum power flows. After the SO-A is solved, the facility obtains production levels and energy prices simultaneously. The inputs on day $D + 1$ are similar to that of day D except for the load profile, which varies each day. Since the energy prices and production levels are obtained simultaneously, the solution (production levels) of the manufacturing facility is the optimal schedule. The energy prices are the actual prices that the facility will pay. That is, the facility makes its operating decisions today and it pays today's energy prices.

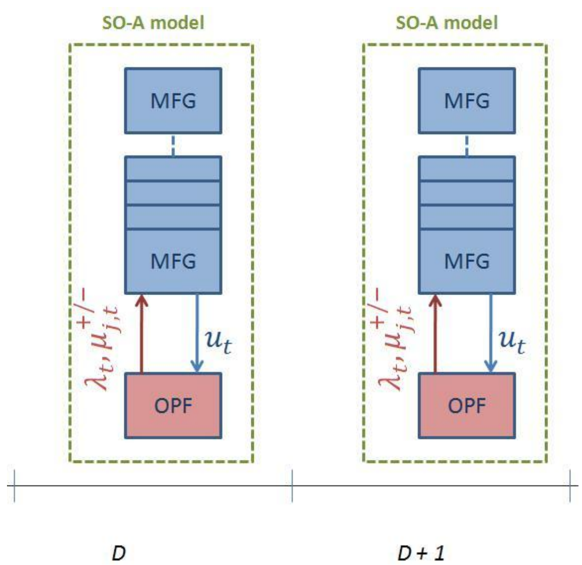

Figure 3.1: SO-A Model

However, there are some disadvantages to this model. Firstly, the other manufacturing facilities do not make their own operating decisions independently. Secondly, the objective function of the model is to minimize the operating cost of only one manufacturing facility. To include other facilities' objective functions would make the problem extremely difficult to solve. Therefore, a second model called SO-B has been developed to explicitly account for the operating decisions of all manufacturing facilities.

3.4 SO-B Model

In this model, the MFG and OPF models are once again combined, but a different approach is used. Firstly, all manufacturing facilities' operating decisions are modeled as linear program formulations. Secondly, to decouple the MFG and OPF models, the manufacturing facilities are assumed to schedule their operations for the day using the market prices of the previous day. The manufacturing facilities independently make their operating decisions by responding to the preceding market day's prices but they pay the LMPs of the operating day. The SO-B model consists of a set of MFG models and one OPF model. They are as follows:

For $f = 1..F$

$$\text{Min } F_f = \sum_t \left\{ I_f^{cost} \cdot i_{f,t} + \hat{P}_{f,t} \cdot \left(E_f \cdot u_{f,t} \right) \right\} \tag{3.46}$$

subject to

initial inventory constraint:

$$i_{f,1} = I_0^f + CP_f \cdot u_{f,1} \tag{3.47}$$

production balance constraints:

$$i_{f,t} = i_{f,t-1} + CP_f \cdot u_{f,t} \qquad t = 2..T \tag{3.48}$$

total demand constraint:

$$i_{f,T} = D_f \tag{3.49}$$

production schedule constraints:

$$0 \leq u_{f,t} \leq 1 \qquad t = 1..T \tag{3.50}$$

nonnegativity constraints:

$$i_{f,t} \geq 0 \qquad t = 1..T \tag{3.51}$$

the optimal power flow model constraints:

For $t = 1..T$

$$\text{Min } z_t = \sum_k C_k \cdot g_{k,t} \tag{3.52}$$

subject to

load balance constraints:

$$\sum_k g_{k,t} = \sum_k L_{k,t} + E_f \cdot u_{f,t} - W_{k,t} \qquad (\lambda_t) \tag{3.53}$$

power flow constraints:

$$\sum_k A_j^k \cdot \left(g_{k,t} - L_{k,t} - E_f \cdot u_{f,t} + W_{k,t}\right) \leq F_{j,t}^{\max} \qquad \left(\mu_{j,t}^{+}\right)\ j = 1..J \tag{3.54}$$

$$\sum_k A_j^k \cdot \left(g_{k,t} - L_{k,t} - E_f \cdot u_{f,t} + W_{k,t}\right) \geq -F_{j,t}^{\max} \qquad \left(\mu_{j,t}^{-}\right)\ j = 1..J \tag{3.55}$$

generation capacity constraint:

$$G_{k,t}^{\min} \leq g_{k,t} \leq G_{k,t}^{\max} \qquad \left(\beta_{k,t}\right)\ k = 1..K \tag{3.56}$$

wind power constraint:

$$0 \leq W_{k,t} \leq W_{k,t}^{max} \qquad k = 1..K \tag{3.57}$$

The objective function (3.46) is the minimizing cost equation of all manufacturing facilities, f. There are two parts to the cost: inventory cost and energy cost. The inventory cost of each facility is calculated as inventory cost multiplied by inventory level. For energy cost, $\hat{P}_{f,t}$ is used because these prices are different at each node and they are the prices on the planning day.

Therefore, the energy cost of facility f is energy consumption of each facility (E_f) and production level of each facility ($u_{f,t}$) multiplied by $\hat{P}_{f,t}$. For constraints (3.47) – (3.51), all facilities have to achieve all constraints and have to meet their daily production demand. In addition, the E_f and production capacity (CP_f) are different at each facility f. Equation (3.52) is the objective function of OPF model that minimizes total generation cost. Constraint (3.53) is the sum of energy dispatched by generator k at time t minus wind power must equal the sum of load at bus k at time t plus load produced by the manufacturing facilities at hour t. The constraints (3.54) and (3.55) are the upper and lower limits of the power flow at line j. That means that the difference between the energy dispatched by the generator and the load at a particular hour multiplied by the Power Transfer Distribution Factors (PTDFs) should be less than the maximum power flow on the corresponding transmission line. Additionally, the dual variables in the parentheses are the dual prices associated with related constraints. These dual variables are used to compute $\hat{P}_{f,t}$. The $\hat{P}_{f,t}$ can be calculated using (3.58)

$$\hat{P}_{k,t} = \hat{\lambda}_t + \sum_j \left(A_j^k \cdot \hat{\mu}_{j,t}^{+} + A_j^k \cdot \hat{\mu}_{j,t}^{-} \right) \tag{3.58}$$

where $\hat{\lambda}_t$, $\hat{\mu}_{j,t}^{+}$, and $\hat{\mu}_{j,t}^{-}$ are from the solution of the OPF model solved the day prior to the operating day.

Figure 3.2 illustrates the interaction between the MFG and OPF models for model SO-B. In the figure, the manufacturing facility plans its operating schedule on day D while using the energy prices of the previous day $D-1$.

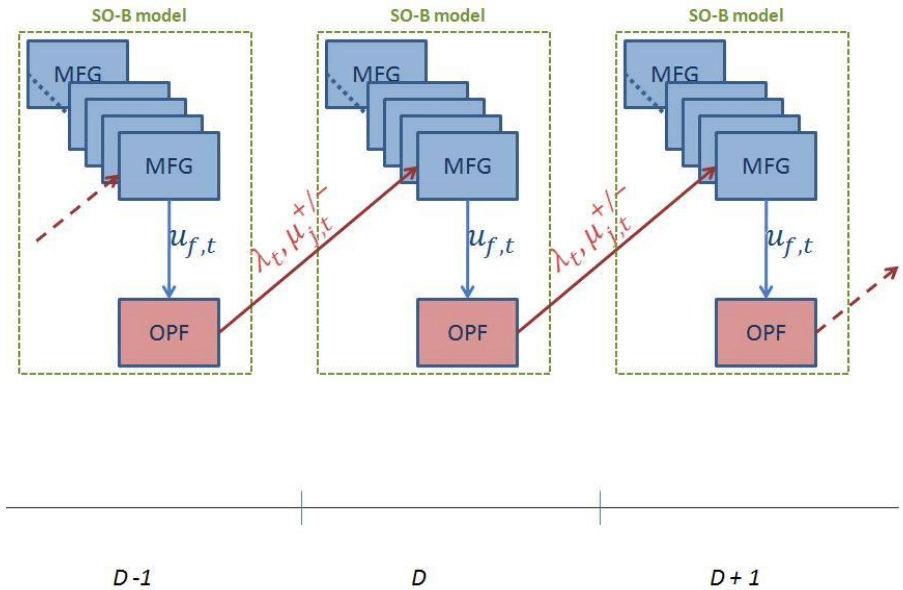

Figure 3.2: SO-B Model

Since the energy prices of day $D-1$ may be different from the energy prices that the facility will pay on the operating day D, the solution (production levels) of the manufacturing facility is not the optimal schedule for the operating day. Therefore, the actual daily costs of the manufacturing facilities are given by (3.59)

$$C_f = \sum_t \{I^{cost} \cdot i_t + [\lambda_t + \sum_{j,f}(A_j^f \cdot \mu_{j,t}^+ + A_j^f \cdot \mu_{j,t}^-)] \cdot (E_f \cdot u_t)\} \tag{3.59}$$

Although the load profile may be at different magnitudes on two consecutive days, they may follow the same hourly profile. For this reason, the manufacturing facilities' operating schedules determined using energy prices from day $D-1$ may possibly be a good solution for day D in terms of the energy prices.

This model can be simply solved because it consists of independent linear programming models. All market participants are modeled as linear program formulations. The production levels of the manufacturing facilities on day D are input to the OPF model of day D that provides the energy prices for day D and also the inputs for the MFG model of day $D + 1$. In this model, all manufacturing facilities make their decisions independently responding to forecasted energy prices. In addition, the SO-B model does not require any sophisticated optimization software, and it can be used in long-term studies.

CHAPTER 4

COMPARISON ANALYSIS OF SYSTEM OPERATING MODELS

To analyze both the SO-A and SO-B manufacturing operating models, market conditions such as load profile, manufacturing data, and power system data are used. The power system consists of 5 buses and 4 generators. The load profile is obtained from the Pennsylvania, New Jersey, and Maryland power pool (PJM) website and corresponds to the hourly load of January 2009. The load is scaled down to fit within the range of the generation capacity. In both models, it is assumed that there are two manufacturing facilities and a power system. For the SO-A model, facility 1, located at bus 1, is assumed to solve the model. The models are coded in AMPL format but two different optimization solvers are used. The SO-A model uses the solver "MPEC", while the SO-B model uses CPLEX.

4.1 Manufacturing and Power System Data

4.1.1 Manufacturing Facilities Data

The two manufacturing facilities are assumed to be located at buses 1 and 2. For the purpose of convenience, it is assumed that there is no initial inventory at either facility. The data of the manufacturing facilities are given in Table 4.1

Table 4.1: The Manufacturing Facility Data

Facility	1	2
Facility capacity (ton)	400	200
Inventory cost ($/ton)	0.07	0.05
Energy consumption (MWh)	45	20
Initial inventory (ton)	0	0
Daily production demand (ton)	6000	3000

4.1.2 Power Network Data

Figure 4.1 illustrates the 5-Bus, 4-Generator power system. There are four different types of generator: coal-powered, gas-powered, nuclear-powered, and oil-powered. The generator data are given in Table 4.2 and the power system data in Table 4.3

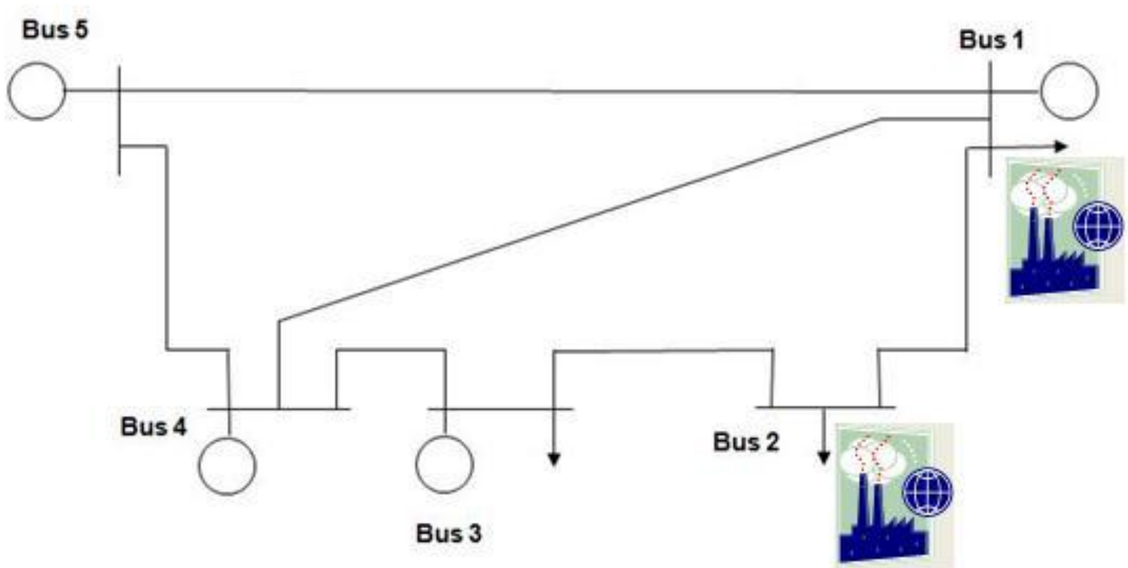

Figure 4.1: 5-Bus, 4-Generator Power System

Table 4.2: Generator Data

Generator	Cost ($/MWh)	Capacity (MW)	Fuel Types
1	72	55	Coal
3	90	260	Oil
4	77	100	Gas
5	49	300	Nuclear

Table 4.3: PTDFs and Max. Power Flow

Line	Injection Node k					$F_{j,t}^{max}$
	1	2	3	4	5	
1-2	0.8235	0.0000	0.1765	0.3529	0.5294	450
2-3	-0.1765	0.0000	-0.8235	-0.6471	-0.4706	300
4-3	0.1765	0.0000	-0.1765	0.6471	0.4706	200
5-4	0.0588	0.0000	-0.0588	-0.1176	0.5735	200
4-1	-0.1176	0.0000	0.1176	0.2353	0.1029	200
5-1	-0.0588	0.0000	0.0588	0.1176	0.4265	200

4.1.3 Load Data

The load data is obtained from the PJM website and corresponds to the load of the PJM East market in the year 2009. The maximum load is 55,443 megawatts, which is reduced to 495 megawatts by the factor 0.009 to be within the total generation capacity of 715 megawatts. In addition, no expansion of generation capacity is assumed. For the analysis, the load for the month of January is used. The average of the scaled loads at each hour of the day is shown in Figure 4.2.

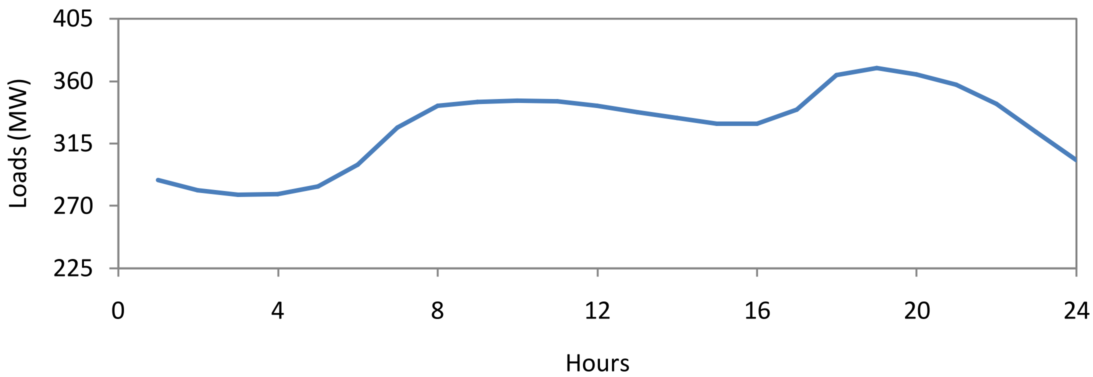

Figure 4.2: Hourly Scaled Load Average in Jan 2009

Notice that the load is comparatively low at the first half of the day and higher at the second half of the day. This implies that the energy costs are higher at later hours of the day.

4.2 Wind Energy Data

Two wind farms are placed in the power system. The first wind farm with a capacity of 15 MW is located on bus 1 and the second wind farm with a capacity of 10 MW is located on bus 2. Both wind farms are assumed to use the same wind turbine model. The wind turbine specifications are adopted from the WinWinD [46]. The specifications are given in Table 4.4.

Table 4.4: Wind Turbine Specifications

Rated power	1000 kW
Cut-in wind speed	3.6 m/s
Rated wind speed	12.5
Cut-out wind speed	22 -25 m/s
Design lifetime	20 years

As shown in Table 4.4, a wind turbine starts generating electricity when the wind speed is at least 3.6 m/s and will be automatically stopped when the wind speed has reached 22 m/s to prevent damage to the turbine. Figure 4.3 illustrates the function used to convert the wind speed into wind electric power.

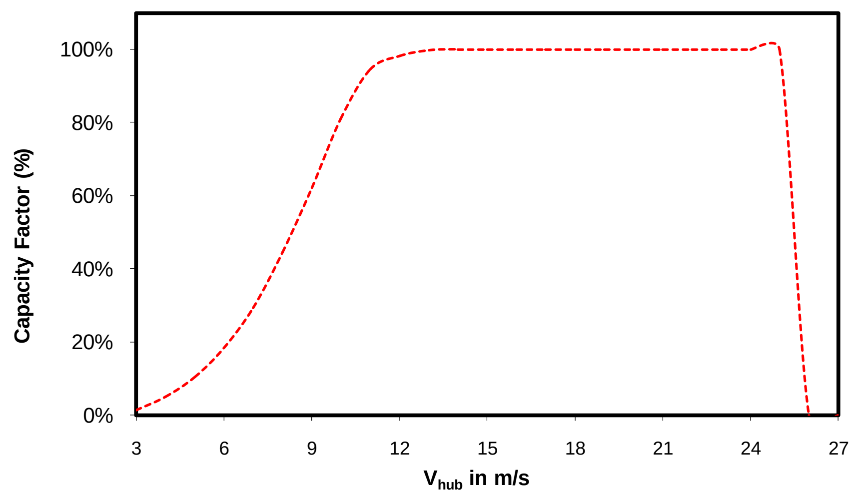

Figure 4.3: Wind Power Output

From Figure 4.3, a wind farm generates electricity at its full capacity when the wind speed is at least 12.5 m/s.

4.3 Comparing Models SO-A and SO-B

The objective of this section is to compare the outputs of the SO-A and SO-B models. There are two types of outputs: the power generating company and the manufacturing facility. The output of the power generating company consists of the daily profit while the output of the manufacturing facility is the daily operating cost. The outputs of the SO-A are based on the manufacturing facility 1 data and these outputs are considered as a reference to the outputs of the SO-B model. In addition, there are two different cases: No Wind Case and With Wind Case. All data for both cases are identical, except that for With Wind Case the additional wind power data are used. For the comparison analysis, just the load for the month of January is used to save time in submitting the SO-A model to the NEOS Server for Optimization for solving.

4.3.1 No Wind Case

The outputs of the models are the power generating company's revenues and costs and the manufacturing facility's operating cost. First, the profits of the power generating company yielded by SO-A and SO-B are observed. The profits are the difference between revenues and costs. The revenues are calculated from loads multiplied by LMPs at a particular time and location while the generating costs are calculated from the generator costs multiplied by the amount of electricity generated by the generators. Figure 4.4 illustrates the daily profits of the power generating company and obtained from the SO-A and SO-B models.

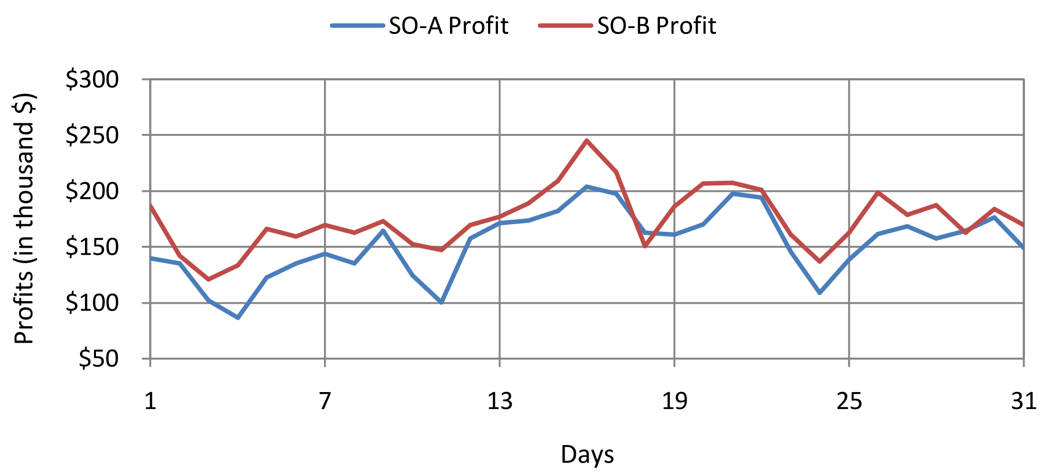

Figure 4.4: Daily Power Generating Company's Profits

Figure 4.4 indicates that the two models yield different results for the power generating company's daily profits.

Second, the operating costs of the manufacturing facility are observed. The cost obtained from solving the SO-A model is called "SO-A cost" and is calculated using equation (3.27). The cost obtained from solving the SO-B model is called "SO-B model cost" and is calculated using equation (3.46). The actual cost of the SO-B model is called "SO-B actual cost" and is obtained from equation (3.59). Figure 4.5 illustrates the daily operating cost for one month of Facility 1 using models SO-A and SO-B.

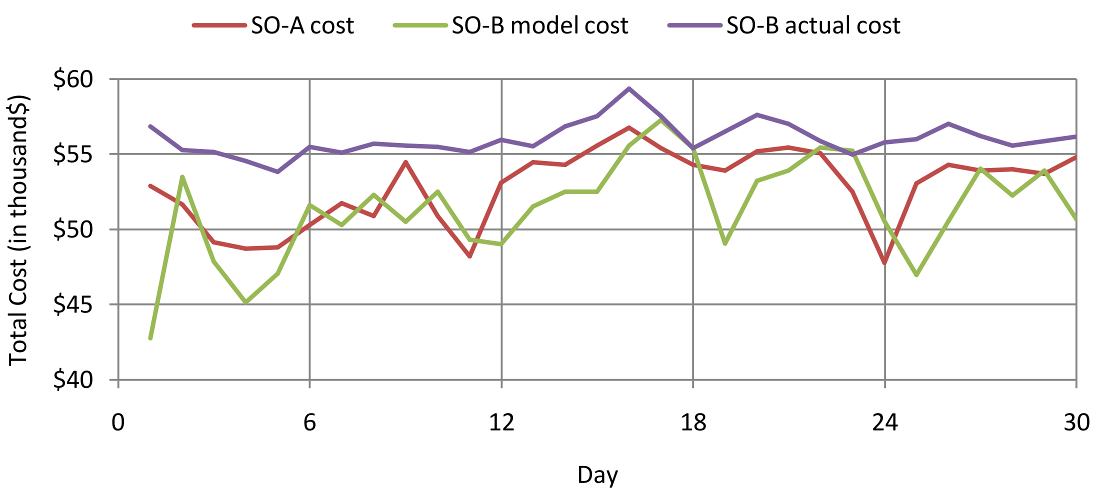

Figure 4.5: Daily Operating Costs of Facility 1

If SO-A is considered to provide a more accurate manufacturing operating cost, the SO-B model and actual costs seem to underestimate and overestimate, respectively, the operating costs computed by the SO-A model. According to the solution, the SO-B model cost at day 1 deviates by a fairly large margin from the SO-A cost and a test of statistical significance will be reported in section 4.3. The variation can be attributed to using inaccurate forecasted energy prices the first time the manufacturing facility operates; therefore, day 1 is removed and not considered. Notice that for the remaining days, the shape of the SO-B model cost curve resembles that of SO-A, so no other days are omitted from future analysis.

4.3.2 With Wind Case

The SO-A and SO-B models are solved by including two wind farms with capacities 15 MW and 10 MW connected to the power grid at buses 1 and 2, respectively. Wind power data from the Pittsburgh airport area of the month of January in the year 2009 are used in the analysis [45]. The wind output curve in Figure 4.3 is used to convert wind speed to wind power. The wind power average for each hour of January 2009 is shown in Figure 4.6.

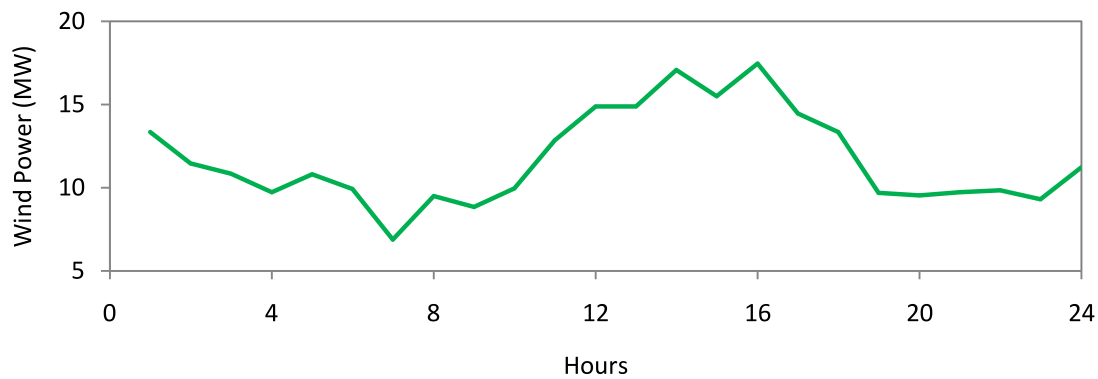

Figure 4.6: Wind Power Average for One Month

Facility 1 is the main facility and the profits of the power generating company are illustrated in Figure 4.7.

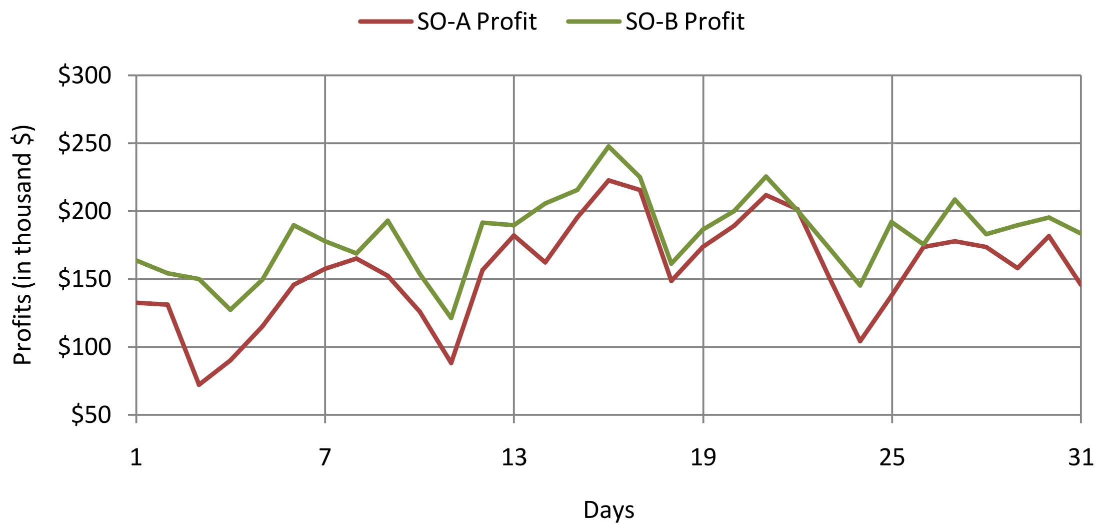

Figure 4.7: Daily Power Generating Company's Profits

Similar to the case in 4.3.1, SO-A and SO-B provide different profit profiles for the power generating company. For the manufacturing facility, the SO-B model underestimates cost while the SO-B actual cost model overestimates costs compared to the SO-A cost model. The profile is equivalent to the No Wind Case in 4.3.1. The total daily operating cost of facility 1 is shown in Figure 4.8.

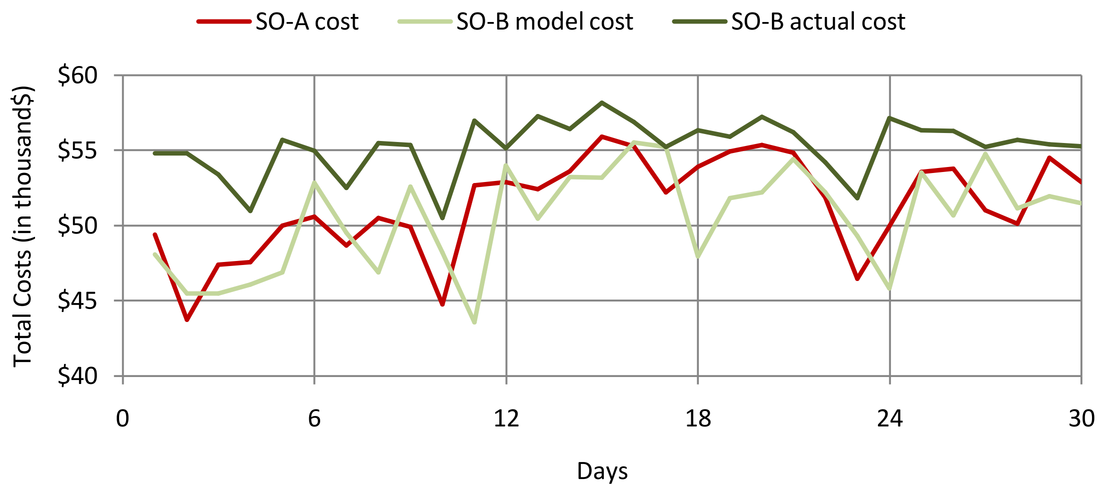

Figure 4.8: Daily Operating Costs of Facility 1

4.4 Statistical Test comparing the Models SO-A and SO-B

As seen in previous sections, the cost curves differ between SO-A and SO-B models in both the No Wind and With Wind case (see Figures 4.5 and 4.8). A statistical test is employed to test the mean differences of the results yielded from the SO-A and SO-B models. The power generating company's profits and the facility's operating costs are the subjects of the test. The hypothesis t -test with 95% confidence is used to test the means of revenues and costs. The hypothesis-testing procedure is as follows:

a) The parameters of interest are μ_1 and μ_2, the mean daily profit/cost using models SO-A and SO-B .

b) $H_0 : \mu_1 = \mu_2$; $H_1 : \mu_1 \neq \mu_2$

c) $\propto = 0.05$

d) The test statistics are

$$t_0 = \frac{\bar{x}_1 - \bar{x}_2 - 0}{s_p\sqrt{\frac{1}{n_1} + \frac{1}{n_2}}}$$

e) Reject H_0 if $t_0 > t_{\frac{\propto}{2}, n_1+n_2-2}$ or $t_0 < -t_{\frac{\propto}{2}, n_1+n_2-2}$

f) Computation

4.4.1 No Wind Case

For the power generating company, $\bar{x}_1$ is the average daily profit obtained from SO-A, and $\bar{x}_2$ is the average daily profit obtained from SO-B. Also, s_1 and s_2 are the standard deviations of the profits of models SO-A, and SO-B, respectively. Finally, the sample sizes of models SO-A and SO-B are denoted by n_1 and n_2 and for this experiment, $n_1 = n_2$. The data of the two models are as follows:

$\bar{x}_1$ = \$152,500, $\bar{x}_2$ = \$174,631 s_1 = \$29,709.60, s_2 = \$27,038.61, and $n_1 = n_2$ = 31.

Therefore, the pooled estimator of σ^2 is

$$s_p^2 = \frac{(n_1 - 1)s_1^2 + (n_2 - 1)s_2^2}{n_1 + n_2 - 2} = 806873343$$

$$s_p = \$28{,}405.52$$

$$t_0 = \frac{\bar{x}_1 - \bar{x}_2 - 0}{s_p\sqrt{\frac{1}{n_1} + \frac{1}{n_2}}} = -3.0674$$

and $t_{0.025,60} = 2.0$ and $-t_{0.025,60} = -2.0$. Therefore, since -3.0674 < -2.0, the null hypothesis can be rejected. It can be concluded that, at the 0.05 level of significance, there is strong evidence that the mean profits differ between both models. A summary of the tests is represented in Table 4.5.

Table 4.5: The Hypothesis Test of Power Generating Company

Hypothesized Mean Difference	0	
α	0.05	
Observations (n)	31	
degree of freedom	60	
$t_{0.025,60}$	2.0000	
Profit	SO-A	SO-B
Mean ($\bar{x}$)	$152,500	$174,631
Variance (s_i^2)	882660110	731086577
Pooled Variance (s_p^2)	806873343	
t_0	-3.0674	

The same procedure is applied to the facility's operating cost but the operating cost at day 1 is removed in order to avoid the variation. The SO-B actual cost is used to test against the SO-A cost. The results are summarized in Table 4.6.

Table 4.6: The Hypothesis Test of Facility 1

Hypothesized Mean Difference	0	
α	0.05	
Observations (n)	30	
degree of freedom	58	
$t_{0.025,58}$	2.0017	
Operating cost	SO-A	SO-B actual
Mean ($\bar{x}$)	$52,851	$5,989
Variance (s_i^2)	6119548	1182435
Pooled Variance (s_p^2)	3650991	
t_0	-6.3600	

Since t_0 is less than the lower critical limit, it can be concluded that, at the 0.05 level of significance, the SO-A cost and SO-B actual cost are significantly different.

4.4.2 With Wind Case

For the With Wind Case, all data of the manufacturing facility and power system are identical to the No Wind Case except that wind power is included. The test of SO-B against SO-A is summarized in Table 4.7.

Table 4.7: The Hypothesis Test of Power generating company

Hypothesized Mean Difference	0	
α	0.05	
Observations (n)	31	
degree of freedom	60	
$t_{0.025,60}$	2.0000	
Profit	SO-A	SO-B
Mean ($\bar{x}$)	$156,095	$182,009
Variance (s_i^2)	1391741863	818605585
Pooled Variance (s_p^2)	1105173724	
t_0	-3.0689	

For the power generating company's revenue and cost, since $t_0 < t_{-0.025,60}$, it can be concluded that, at $\propto = 0.05$, the mean revenues and costs yielded from SO-A and SO-B are significantly different.

To test for significance in the comparison between the solutions from the SO-A and SO-B models for With Wind Case, the means of daily operating costs of manufacturing facility 1 and wind power data are included while the solutions of the SO-A and SO-B models are tested. The summary of the hypothesis test is displayed in Table 4.8.

Table 4.8: The Hypothesis Test of Facility 1

Hypothesized Mean Difference	0	
α	0.05	
Observations (n)	30	
degree of freedom	58	
$t_{0.025,58}$	2.0017	
Operating cost	SO-A	SO-B actual
Mean ($\bar{x}$)	$51,360	$55,263
Variance (s_i^2)	10125652	3373214
Pooled Variance (s_p^2)	6749433	
t_0	-5.8181	

For the facility cost, since $t_0 < t_{-0.025,60}$, it can be concluded that, at $\propto = 0.05$, the mean costs of SO-A and SO-B actual costs are different.

In summary, the statistical results show that there is strong evidence that the profits of the power generating company yielded from the SO-A and SO-B models are significantly different. Therefore, a correction model is required to forecast the correct profits of the power generating company in a long term study. Similarly, for the operating cost of the manufacturing facility, the test indicates that the operating costs of firm 1 yielded from the SO-A and SO-B models are significantly different. Therefore, a correction model is needed, in this case, to approximate the outputs of the SO-A model using the SO-B model.

4.5 Correction Model

The statistical results from the previous section indicate that the power generating company's profit and the manufacturing facilities' operating cost yielded by the SO-B model require a correction model to adjust the SO-B output.

Even though the means of the daily profits of the power generating company and the daily operating costs of the manufacturing facility yielded from the SO-A and SO-B models are significantly different, the correlation of the two models (see Figure 4.9) indicates that one model can be used to predict the outcome of the other.

4.5.1 No Wind Case

To observe the correlation of the output from models SO-A and SO-B, the manufacturing facilities' operating cost is used as an example. SO-B actual costs and the SO-A cost are plotted to demonstrate the relationship of the costs yielded from the two models. The load is another parameter that has correlation to the SO-A cost. Therefore, the load against the SO-A cost is observed. The plots of SO-B actual costs and load, plotted against SO-A cost, are displayed in Figures 4.9 and 4.10.

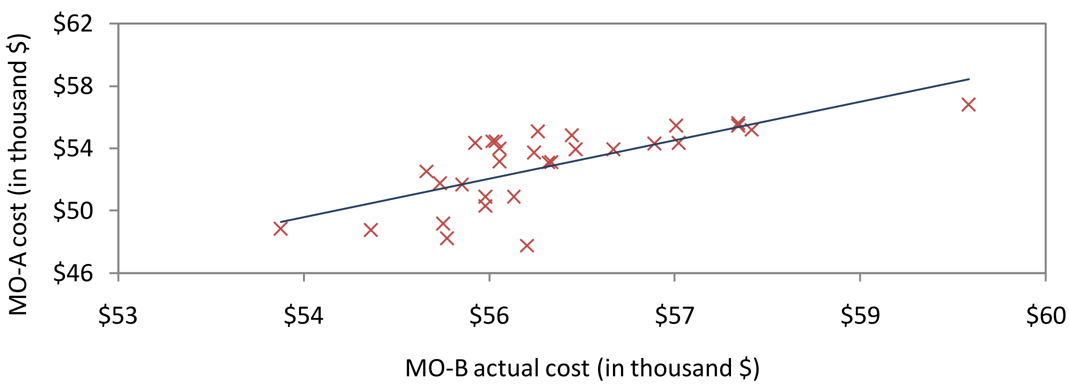

Figure 4.9: SO-B Actual Cost Versus SO-A Cost

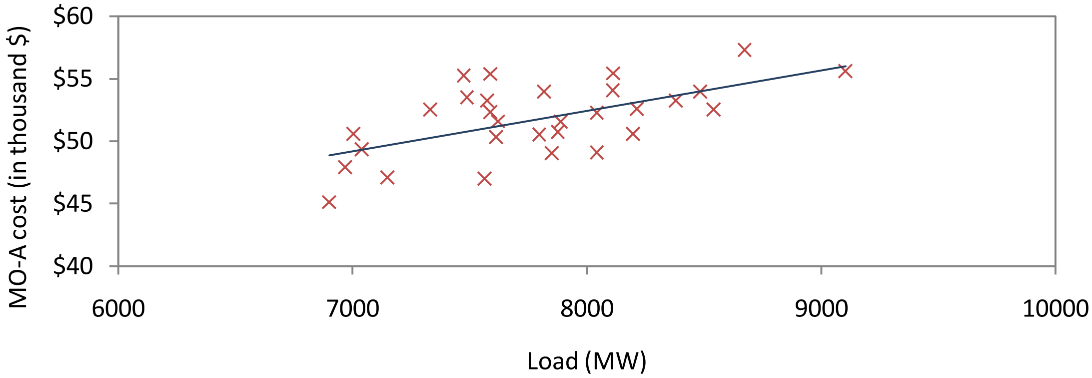

Figure 4.10: Load Versus SO-A Cost

The SO-B model actual cost profile seems to coincide with that of SO-A and, according to Figure 4.9, the costs of the two models are correlated. In addition, Figure 4.10 shows a positive correlation between load and SO-A cost. That is, as the load increases, the SO-A cost increases.

The multiple linear regression technique is used to verify the relationship of the operating cost between models SO-A and SO-B and to construct the correction model. The method of least squares is used to estimate the regression coefficients. The normal equations that are used for the analysis are as follows:

The estimated regression model

$$Y = \beta_0 + \beta_1 x_1 + \beta_2 x_2 + \cdots + \beta_k x_k + \epsilon \tag{4.1}$$

$$y_i = \beta_0 + \beta_1 x_{i1} + \beta_2 x_{i2} + \cdots + \beta_k x_{ik} + \epsilon_i, \; i = 1,2, \dots, n \tag{4.2}$$

where $\epsilon_i = y_i - E(y_i)$

The least squares estimates of the intercept and slope

$$
\begin{aligned}
n\hat{\beta}_0 + \hat{\beta}_1 \textstyle\sum_{i=1}^{n} x_{i1} \quad &+ \hat{\beta}_2 \textstyle\sum_{i=1}^{n} x_{i2} \quad + \cdots + \hat{\beta}_k \textstyle\sum_{i=1}^{n} x_{ik} \quad = \textstyle\sum_{i=1}^{n} y_i \\
\hat{\beta}_0 \textstyle\sum_{i=1}^{n} x_{i1} + \hat{\beta}_1 \textstyle\sum_{i=1}^{n} x_{i1}^2 \quad &+ \hat{\beta}_2 \textstyle\sum_{i=1}^{n} x_{i1}\, x_{i2} + \cdots + \hat{\beta}_k \textstyle\sum_{i=1}^{n} x_{ik}\, x_{ik} = \textstyle\sum_{i=1}^{n} x_{i1} y_i \\
\vdots \qquad\qquad \vdots \qquad\qquad & \vdots \qquad\qquad \vdots \qquad\qquad \vdots \\
\hat{\beta}_0 \textstyle\sum_{i=1}^{n} x_{ik} + \hat{\beta}_1 \textstyle\sum_{i=1}^{n} x_{ik} x_{i1} &+ \hat{\beta}_2 \textstyle\sum_{i=1}^{n} x_{ik}\, x_{i2} + \cdots + \hat{\beta}_k \textstyle\sum_{i=1}^{n} x_{ik}^2 = \textstyle\sum_{i=1}^{n} x_{ik} y_i
\end{aligned}
\tag{4.3}
$$

Computation

The total daily costs of SO-A and SO-B actual costs and the total daily load are used for the regression analysis. The objective of the regression analysis is to construct the model to predict SO-A from the best available SO-B actual and the load.

In the multiple linear regression model, the daily operating cost of the manufacturing facility yielded from the SO-A model is the response variable and the SO-B actual cost and daily total load are the predictor variables. The remaining calculations are as follows:

Let Y be the daily operating cost yielded from SO-A; let x_1 be the SO-B actual cost; and let x_2 be the daily total load. The multiple linear regression model is fitted as

$$Y = \beta_0 + \beta_1 x_1 + \beta_2 x_2 + \epsilon \tag{4.4}$$

Then, $n = 30$, $\sum_{i=1}^{30} y_i = 1{,}585{,}539.30$

$\sum_{i=1}^{30} x_{i1} = 1{,}679{,}672.10$, $\sum_{i=1}^{30} x_{i2} = 234{,}062.22$

$\sum_{i=1}^{30} x_{i1}^2 = 94{,}077{,}569{,}386$ $\sum_{i=1}^{30} x_{i2}^2 = 1{,}834{,}457{,}735$

$\sum_{i=1}^{30} x_{i1} x_{i2} = 13{,}119{,}782{,}859$ $\sum_{i=1}^{30} x_{i1} y_i = 88{,}829{,}136{,}589$

$\sum_{i=1}^{30} x_{i2} y_i = 1{,}240{,}505{,}750$

Therefore, the solution to this set of equations is

$$\hat{\beta}_0 = 51507, \qquad \hat{\beta}_1 = -0.743, \qquad \hat{\beta}_2 = 5.50$$

And, the fitted regression equation is

$$\hat{y} = 51507 - 0.743x_1 + 5.50x_2$$

or

$$SO - A = 51507 - 0.743 \cdot SO - B\ actual + 5.50 \cdot Load$$

4.5.1.1 The Model Adequacy

The approximate model from the previous section is tested to validate the model. Residual analysis, coefficient of determination, and normality are employed.

4.5.1.1.1 Residual Analysis

There are two types of residual analyses that are used to justify the model. Firstly, the residual plot is displayed in Figure 4.11. The residual is obtained by $e_i = y_i - \hat{y}_i$ where y_i is an actual observation and $\hat{y}_i$ is the corresponding predicted value from the forecasting model. The residuals are plotted chronologically for 30 days.

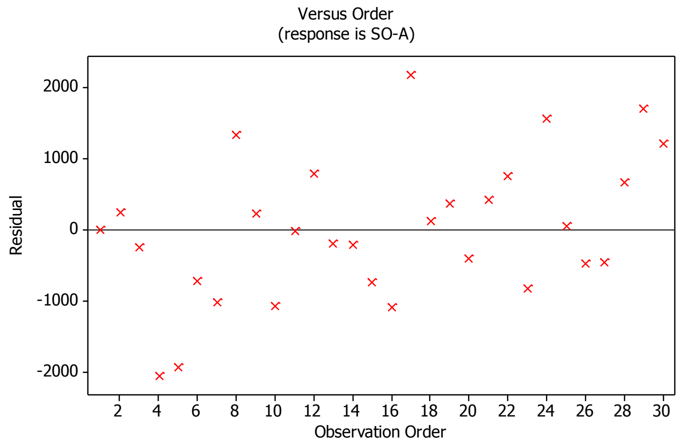

Figure 4.11: Residual Plots

Since residuals are randomly scattered between upper and lower bounds, it can be concluded that, in terms of residual analysis, the model is adequate.

Another plot is the plot of residuals that are plotted against the predicted value, $\hat{y}$. Figure 4.12 illustrates the residuals versus predicted SO-A.

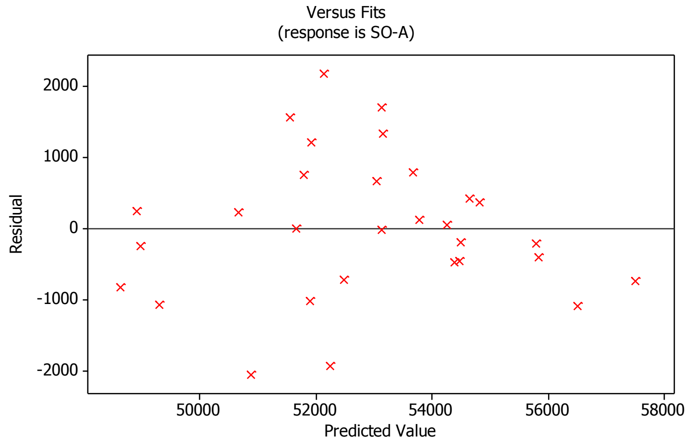

Figure 4.12: Plot of Residuals versus Predicted SO-A

The plot shows that the residuals are randomly plotted; therefore, there is no violation of the model adequacy.

4.5.1.1.2 Coefficient of Determination (R^2)

To verify the good relationship of two models, an implement should be used. The coefficient of determination (COD) is used to validate the adequacy of a regression model. COD ranges between 0 and 1 ($0 \leq R^2 \leq 1$) and it can be obtained by

$$R^2 = 1 - \frac{SS_E}{SS_T} \tag{4.5}$$

where SS_E is the error sum of square which can be calculated as $SS_E = \sum_{i=1}^{n} e_i^2$ while SS_T is the total sum of squares of the response variable y which can be obtained by $SS_T = \sum_{i=1}^{n}(y_i - \bar{y})^2$. Therefore, COD of this model is as follows:

$$R^2 = 1 - \frac{29151677}{177466882} = 0.8357$$

It can be concluded that the forecasting model accounts for 83.57% of the variability in the data.

4.5.1.1.3 The Normality Check

The sample size (n) of this experiment is 30, which is comparatively small. Therefore, the frequency histograms may not be meaningful or adequate to validate the model. A normal plot of residuals could provide more accuracy for the model validation. As before, the residual, e_i can be calculated as ordered $e_i = y_i - \hat{y}_i$ and the cumulative normal probability can be obtained by $\frac{i}{n+1}$. Figure 4.13 illustrates the normal probability plot of residuals.

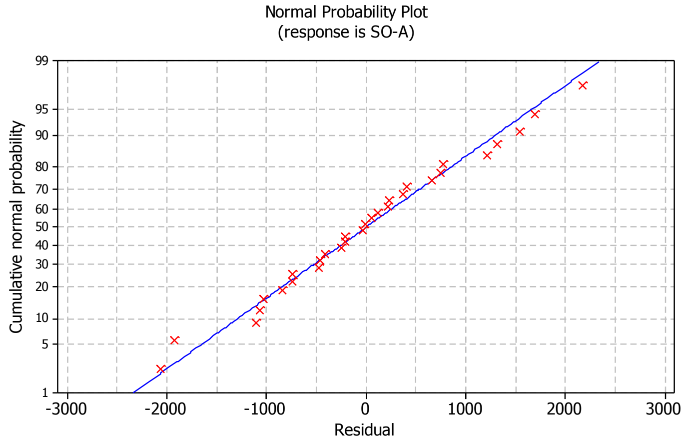

Figure 4.13: Normal Probability Plot of Residuals

The plot demonstrates that the residuals fall approximately along a straight line. Therefore, it can be concluded that there is no severe departure from the normality.

For the economic analysis, it is assumed that there are two manufacturing facilities on the power grid. Therefore, the procedure for constructing a correction SO-A model for manufacturing facility 2 is repeated. In addition, the same procedure is applied for the power generating company's profit. The summary of the forecasting SO-A model is illustrated in Table 4.9

Table 4.9: The Correction Model of No Wind Case

Participant	Correction SO-A model	R^2
Power generating company	$-247131 - 0.027 \cdot PP_d + 50.69 \cdot L_d$	85.97%
Facility 1	$51507 - 0.743 \cdot FC_{1,d} + 5.50 \cdot L_d$	83.57%
Facility 2	$17220 - 0.514 \cdot FC_{2,d} + 2.38 \cdot L_d$	81.10%

where power generating company and Facility 1 are the correction models for the power generating company's daily profit and the manufacturing facility's operating cost when Facility 1 solves the SO-A model and

PP_d = daily profits of power generating company obtained from SO-B,

$FC_{f,d}$ = actual daily operating costs of manufacturing facility obtained from SO-B, and

L_d = total daily load.

4.5.2 With Wind Case

The procedure for constructing and testing the forecasting model used in the No Wind Case is repeated except for the addition of wind power. Wind power is another variable that is used to construct the forecasting SO-A model in this case. Since having more variables makes the model more complex, the MINITAB software is used to construct the correction model. The correction models of the power generating company and the manufacturing facilities are summarized in Table 4.10.

Table 4.10: The Correction Models of With Wind Case

Participant	Correction SO-A model	R^2
Power generating company	$-316247 + 0.263 \cdot PP_d + 53.8 \cdot L_d + 20.3 \cdot W_d$	89.3%
Facility 1	$3825 + 0.247 \cdot FC_{1,d} + 4.43 \cdot L_d - 2.28 \cdot W_d$	78.5%
Facility 2	$4194 + 0.046 \cdot FC_{2,d} + 2.25 \cdot L_d - 1.49 \cdot W_d$	79.3%

where

W_d = total daily wind power

4.6 Conclusion

For the power generating company, the results of daily profits calculated from SO-A and SO-B show that the results obtained from the two models are significantly different at the 0.05 level of significance for both cases: No Wind and With Wind. Therefore, a correction model for these outputs is required. The correction models of the power generating company's daily profits for cases No Wind and With Wind are developed and are as follows:

Model 1: The Correction model of the power generating company's profits with No Wind.

Model 2: The Correction model of the power generating company's profits with Wind.

For the manufacturing facilities, since SO-A and SO-B have different approaches towards making operating decisions, the way to compute the daily operating costs is also different. The results yielded by the two models are significantly different. Therefore, regression analysis is employed to test the relationship between SO-A and SO-B and to construct the correction model of SO-A via SO-B actual and load profile for the No Wind and With Wind cases. Four correction models of the manufacturing facility's operating cost are constructed and are as follows:

Model 1: The Correction model when facility 1 is the main facility for No Wind Case.

Model 2: The Correction model when facility 2 is the main facility for No Wind Case.

Model 3: The Correction model when facility 1 is the main facility for With Wind Case.

Model 4: The Correction model when facility 2 is the main facility for With Wind Case.

The correction SO-A models have proven to be adequate through residual analysis, coefficient of determination, and normality tests. For the daily operating cost of the manufacturing facility, the correction model cannot be used alone to obtain the result but must be used along with the SO-B model to translate the results from solving the SO-B model into the SO-A costs that are used for the economic analysis purposes. Therefore, the SO-B model is used to obtain decision variables for long-term studies while the correction SO-A model is used along with SO-B in an economic analysis to obtain more accurate results.

In summary, the SO-B model and the correction models are used for long-term economic analysis. The SO-B model is solved using the commercial package CPLEX. The results yielded by the SO-B will be converted to the correct values using the correction models. These values will be used further for economic analysis.

CHAPTER 5

ECONOMIC ANALYISIS OF WIND ENERGY INVESTMENT

A manufacturing facility has a number of operating expenses, one of them energy to operate its equipment. In order to reduce operating energy costs, a manufacturing firm can self-produce its energy. Among all power generating technologies, wind power generation can provide multiple direct and indirect benefits, and thus has become very attractive. The Production Tax Credit (PTC) is offered for renewable sources generating electricity for a period of 10 years [1]. In addition, generating power from wind can reduce emissions of carbon dioxide (CO_2), which conventional power generation plants create. According to [47], if at any time in the near future, the US Congress passes any CO_2 regulations, the businesses that generate over 250 tons of CO_2 emissions annually would be affected by the regulations. Approximately one million mid-size to large business buildings, about 200,000 manufacturing plants, and 20,000 large farms would have to comply with the carbon dioxide regulations under these circumstances. Investing in wind power generation can help these facilities avoid this scenario. Another advantage of wind power investment is its quick installation. A wind power installation requires approximately 20 days [48] while a nuclear power plant construction requires around four years [49]. For these reasons, wind energy investment formulations are developed and an economic analysis is performed in this chapter.

5.1 Wind Farm Characteristics

In general, a wind farm is made up of several wind turbines and generates from 108 to 780 megawatts. A single wind turbine itself can generate from 250 kilowatts to 7.58 megawatts [35] and it has a useful life of 20 years [35][50]. The Asset Depreciation Range of a wind turbine falls between 16 and 20 years and the recovery period is approximately 10 years. Therefore, the wind turbine is classified as a ten-year Modified Accelerated Cost Recovery System (MACRS) asset and, consequently, 10-year MACRS is applied to wind turbines for depreciation purposes. In addition, the salvage value of the asset is also assumed to be depreciated under the 10-year MACRS. For the sake of simplicity, it is assumed that a wind farm will be owned for 5 years. The depreciation schedule is presented in Table 5.1.

Table 5.1: MACRS Depreciation Schedule for Class 10 years

	Class	10
Year	Depreciation Rate	200%
1		10.00
2		18.00
3		14.40
4		11.52
5		9.22
6		7.37
7		6.55
8		6.55
9		6.56
10		6.55
11		3.28

(Source: Contemporary Engineering Economic 5th edition, C.S.Park)

5.2 General Engineering Economic Formulas

All formulas presented in this section are basic formulas used in the energy investment economic analysis. The present worth, annual equivalent worth and future worth formulas are also used in the energy investment economic analysis. In addition, the capital recovery cost is used to calculate the annual equivalent cost of a wind farm.

Present worth formula:

$$PW = \sum_{d=0}^{N} \frac{X_d}{(1+i)^d} \tag{5.1}$$

This formula converts future values to present worth. In other words, this formula brings the future single payment back to time zero. In addition, this method is used to transform a project's cash flow to a net present worth.

Capital recovery:

$$AE = PW \cdot \left[\frac{i(1+i)^N}{(1+i)^N - 1}\right] \tag{5.2}$$

This formula converts single payments to equal payments. The formula also transforms revenues and costs of the investment to equal payment series. The annual equivalence can be revenue or cost, depending on types of cash flow.

Capital recovery cost:

$$CR(i) = (I - S)\left[\frac{i(1+i)^N}{i(1+i)^N - 1}\right] + iS \tag{5.3}$$

Capital recovery cost or ownership cost converts one-time cost of the investment to its annual equivalent over the life of the project.

Effective Interest rate:

$$i = \left(1 + \frac{r}{CK}\right)^{c} - 1 \tag{5.4}$$

The revenues and costs are calculated on a daily basis and interest rate is assumed to be compounded daily. The interest rate is a nominal interest rate with a daily compounding period. The formula translates a nominal interest rate into effective interest rate.

5.3 Energy Investment Formulas: No Wind Case

These formulas are developed as a benchmark. The power system is assumed to have no wind power. The daily revenues and costs of a power plant and daily operating cost of a manufacturing facility can be calculated as

The power generating company's daily revenue:

$$PR_d = \sum_{t=1..24} P_{k,d,t} \cdot L_{k,d,t} \tag{5.5}$$

The power company receives a daily revenue calculated by the sum of the LMP ($P_{k,d,t}$) multiplied by the load ($L_{k,d,t}$).

The power generating company's daily cost:

$$PC_d = \sum_k \sum_{t=1..24} C_k \cdot g_{k,d,t} \tag{5.6}$$

The power company's daily cost is the dispatched generating units for each hour (C_k) multiplied by electricity generated by generating unit k ($g_{k,d,t}$).

The manufacturing facilities are located on different buses and receive different LMPs because of the buses they are located on (facilities f are located on buses k so that they receive LMP at bus *k*). In addition, the revenue of the facilities is constant because they manufacture a certain amount of their product daily. At this point, the revenue is disregarded and only a daily operating cost is taken into account. If the daily operating cost can be reduced, the manufacturing facility can make more profit. The daily operating cost of the manufacturing facilities can be calculated as

The manufacturing facilities' daily operating cost of facility *f*:

$$FC_{f,d} = \sum_{t=1..24} I_f^{cost} \cdot i_{f,d,t} + E_f \cdot P_{k,d,t} \cdot u_{f,d,t} \quad (5.7)$$

A manufacturing facility's two costs are considered: inventory cost and energy cost. The daily inventory cost is the inventory cost (I_f^{cost}) multiplied by the inventory level ($i_{f,d,t}$) the facility keeps at each hour. For the daily energy cost, the facility pays when they operate the machine at LMP ($P_{k,d,t}$) rate multiplied by their energy consumption factor (E_f) and production level ($u_{f,d,t}$) at a particular hour.

5.4 Energy Investment Formulas: Third Party Investment Case

In this case, the power company buys wind power from a third party. The revenues and costs of the power company are as follows:

The power generating company's daily revenue:

$$PR_d = \sum_{t=1..24} P_{k,d,t} \cdot L_{k,d,t} \quad (5.8)$$

In this case, the daily revenue of the power company is still the same as (5.5). However, LMPs could be lower since wind electric power is connected to the power grid.

The power generating company's daily cost:

$$PC_d = \sum_{t=1..24} C_k \cdot g_{k,d,t} + P_{k,d,t} \cdot W_{k,d,t} \tag{5.9}$$

For this case, the power generating company, in contrast to the manufacturing facility, pays an extra cost of buying wind power. Then, the cost of wind power is added to an existing generation cost. The additional cost of purchasing wind power can be calculated by LMP ($P_{k,d,t}$) multiplied by wind power ($W_{k,d,t}$) at a particular bus and period.

The daily cost of the manufacturing facility remains the same as Case No Wind in (5.7), that is:

The manufacturing facilities' daily operating cost of facility *f*:

$$FC_{f,d} = \sum_{t=1..24} I_f^{cost} \cdot i_{f,d,t} + E_f \cdot P_{k,d,t} \cdot u_{f,d,t} \tag{5.10}$$

The calculation is identical to (5.7)

Since a third party invests in wind farms, the third party receives the benefits from wind but pays a cost. The third party earns benefits from selling wind power to the power grid and receives incentives generated from the government for wind power that it produces.

Third party's daily revenue:

$$TR_d = \sum_{t=1..24} P_{k,d,t} \cdot W_{k,d,t} + PT \cdot W_{k,d,t} \tag{5.11}$$

The daily revenue of a third party is obtained by the amount of wind electric power generated ($W_{k,d,t}$) multiplied by LMP ($P_{k,d,t}$) at which the wind power is sold and added to the incentives (PT).

Even though the fuel cost of the wind power generator is free, the wind farm owner has to pay some costs: maintenance cost and capital recovery cost. The maintenance cost varies depending on the type and size of the wind power generator. For the sake of simplicity, it is assumed in this research that daily maintenance cost is mitigated. Therefore, the only cost that a third party has to pay is the capital recovery cost. The capital recovery cost can be calculated using (5.3), where I is the investment cost, S is the salvage value at the final period of owning the machine, and i is the effective interest rate.

5.5 Energy Investment Formulas: Manufacturing Facility Investment Case

When investing in a wind farm, a manufacturing facility pays two types of costs. Firstly, the facility pays daily operating and maintenance (O&M) cost and secondly, the facility pays the capital recovery cost or ownership cost. The O&M cost is assumed to be mitigated because it varies and is a very small portion compared to the capital recovery cost. The capital recovery cost is the conversion of the initial cost and the salvage values of the machines into annual equivalence.

For the power company, the daily revenue and cost of the company remains the same as equations (5.8) and (5.9). In addition, the revenues and costs of the company are still identical when buying wind from a third party but this time, the power company buys wind power from the manufacturing facilities instead.

The power generating company's daily revenue:

$$PR_d = \sum_{t=1..24} P_{k,d,t} \cdot L_{k,d,t} \tag{5.12}$$

In this case, the daily revenue of the power company is still the same as (4.5)

The power generating company's daily cost:

$$PC_d = \sum_{t=1..24} C_k \cdot g_{k,d,t} + P_{k,d,t} \cdot W_{k,d,t} \tag{5.13}$$

The Manufacturing Facilities daily operating cost of facility *f*:

$$FC_{f,d} = \sum_{t=1..24} I_f^{cost} \cdot i_{f,d,t} + E_f \cdot P_{k,d,t} \cdot u_{f,d,t} - P_{k,d,t} \cdot W_{k,d,t} - PT \cdot W_{k,d,t} \tag{5.14}$$

In this case, the daily operating cost of a manufacturing facility could be reduced because the facilities benefit from selling wind power to the grid as well as receiving incentives from generating wind. The additional daily saving can be calculated by wind power generated ($W_{k,d,t}$) multiplied by LMP ($P_{k,d,t}$) and incentive (PT).

For the capital recovery cost, the facility pays capital recovery cost of a wind farm it owns, which can be calculated using (5.3).

5.6 Energy Investment Formulas: Power Generating Company Investment Case

In this case, the power generating company owns two wind farms but they are located on different buses. The company then pays the investment cost of the wind power but will receive the revenues from selling wind power and an incentive. In addition, the power company will receive the salvage value of wind farms in the final year of owning them.

The power generating company's daily revenue:

$$PR_d = \sum_{t=1..24} P_{k,d,t} \cdot L_{k,d,t} + PT \cdot W_{k,d,t} \tag{5.15}$$

The power company receives revenue from selling electricity at LMP and earns the incentive for generating wind power. The additional daily revenue comes from the incentive and it can be calculated as wind power generated at a particular location and time ($W_{k,d,t}$) multiplied by incentive (PT).

The power generating company's daily operating cost:

$$PC_d = \sum_{t=1..24} C_k \cdot g_{k,d,t} \tag{5.16}$$

The company pays only the generation cost but it is implied that the company pays lower generation costs since wind power reduces LMP. In addition, the company has to pay the investment cost of the wind farm.

The manufacturing facilities' daily operating cost of facility *f*:

$$FC_{f,d} = \sum_{t=1..24} I_f^{cost} \cdot i_{f,d,t} + E_f \cdot P_{k,d,t} \cdot u_{f,d,t} \tag{5.17}$$

A manufacturing facility's daily operating cost implies that the facility will not earn benefit directly from wind power but could obtain benefits when wind power is included in the electricity grid. The daily cost equation remains unchanged but the facility could pay less because wind power reduces LMP.

CHAPTER 6

NUMERICAL RESULTS

In this chapter, a small power system is used to demonstrate the operating model and investment economic analysis. A base scenario called “no wind” is designated as a reference to the scenarios “with wind”. Three cases are considered when there is wind energy investment, namely third party wind energy investment, manufacturing facility wind energy investment, and power company wind energy investment. An economic comparison analysis is performed using the results from the system operating model, correction model, and economic analysis of energy investment described in chapter 3, chapter 4, and chapter 5, respectively. The system operating model SO-B is used to obtain the daily profits of the power company and the daily costs of the manufacturing facilities for the study period. The power generating company’s profits and the manufacturing facilities’ costs are adjusted by using the correction models described in chapter 4. The study is performed for a period of 5 years or 1,825 days.

6.1 System Description

The same power system described in chapter 4 is used to formulate investment of wind energy. It is assumed that two wind farms will be added to the existing power network. Wind farm 1 with a capacity of 15 MW is placed on bus 1 and wind farm 2 with a capacity of 10 MW is placed on bus 2. The investment cost of a wind farm is assumed to be one million dollars per megawatt [52]. Therefore, the investment costs of wind farms 1 and 2 are \$15 million and \$10 million, respectively. Both wind farms are assumed to use the same wind turbines. The wind turbine specifications are described in chapter 4.

6.2 Case A: No Wind

This case provides the manufacturing operating costs and the power company profits when no additional generating capacity is added to the power system. For the power company, the operating (SO-B) model provides daily revenues (PR_d) and daily costs (PC_d) which are obtained by equations 5.5 and 5.6 in chapter 5. These results are used to calculate the power generating company's daily profits (PP_d), which are adjusted by the correction model:

$$\widehat{PP}_d = -247131 - 0.027 \cdot PP_d + 50.69 \cdot L_d$$

where

$$PP_d = PR_d - PC_d,$$

The adjusted profits will be used in the investment economic analysis to compute the annual profit of the power company. To calculate the annual profit (or annual equivalent worth), a nominal interest rate of 5% per year compounded daily is used. The power company's daily profits are first converted into the net present value using the daily effective interest rate. The nominal interest rate is converted to an effective interest rate by using (5.4) in chapter 5. For the nominal interest rate (r) = 5%, the daily effective interest is

$$i = \left(1 + \frac{5\%}{1(365)}\right)^1 - 1 = 0.0137\% \text{ per day compounded daily}$$

If the power company's daily profits are $\widehat{PP}_d$, shown below in Figure 6.1 for year 1, the net present value of the power company's daily profits can be calculated as

$$PW = \sum_{d=1}^{1825} \frac{\widehat{PP}_{1,d}}{(1+i)^d}$$

$$PW = \$\,222{,}474{,}891$$

To convert the net present value into an annual basis, the annual effective interest rate is required and can be calculated by

$$i = \left(1 + \frac{5\%}{365}\right)^{365} - 1 = 5.13\% \text{ per year compounded yearly}$$

The annual equivalent profit (AEP) is computed as

$$AEP = PW \cdot \left[\frac{i(1+i)^5}{(1+i)^5 - 1}\right]$$

$$AEP = \$51{,}566{,}269$$

Therefore, the annual equivalent profit of the power company at r = 5% is approximately \$51 million

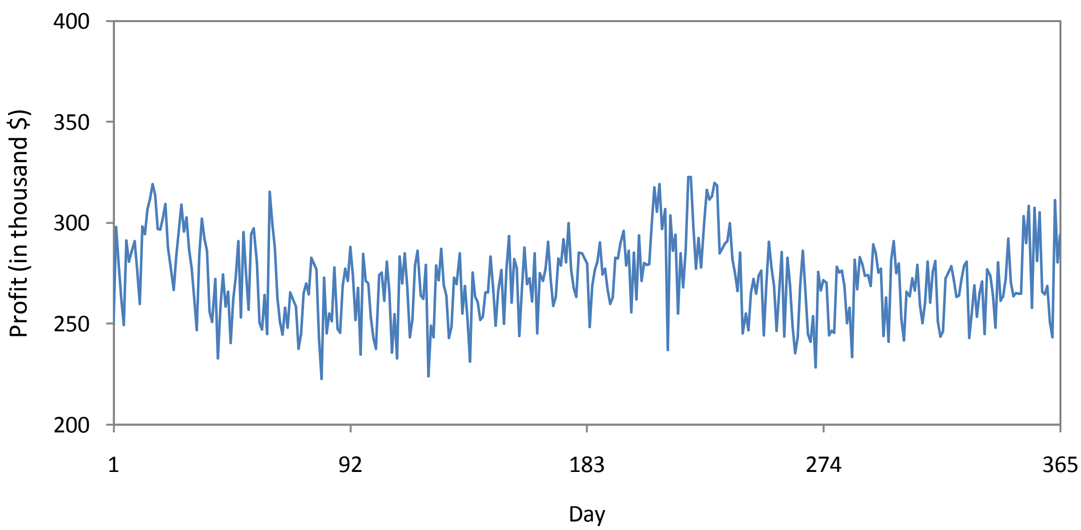

Figure 6.1: The Power Company's Daily Profits in Year 1

For the manufacturing facility, the daily operating costs produced by the SO-B model are converted into daily actual operating costs ($FC_{f,d}$) using equation 3.59 in chapter 3. The actual costs are then adjusted by the correction model described in chapter 4. The correction models are as follows:

For Facility 1: $\widehat{FC}_{1,d} = 51507 - 0.743 \cdot FC_{1,d} + 5.50 \cdot L_d$

For Facility 2: $\widehat{FC}_{2,d} = 17220 - 0.514 \cdot FC_{2,d} + 2.38 \cdot L_d$

Figures 6.2 and 6.3 show the adjusted actual daily cost for year 1 of Facility 1 and Facility 2.

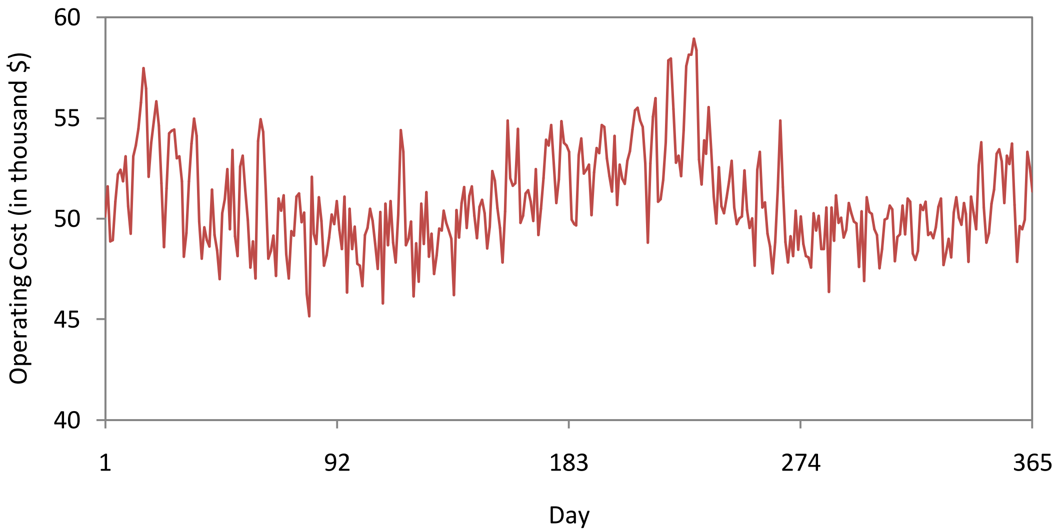

Figure 6.2: Facility 1's Daily Operating Cost

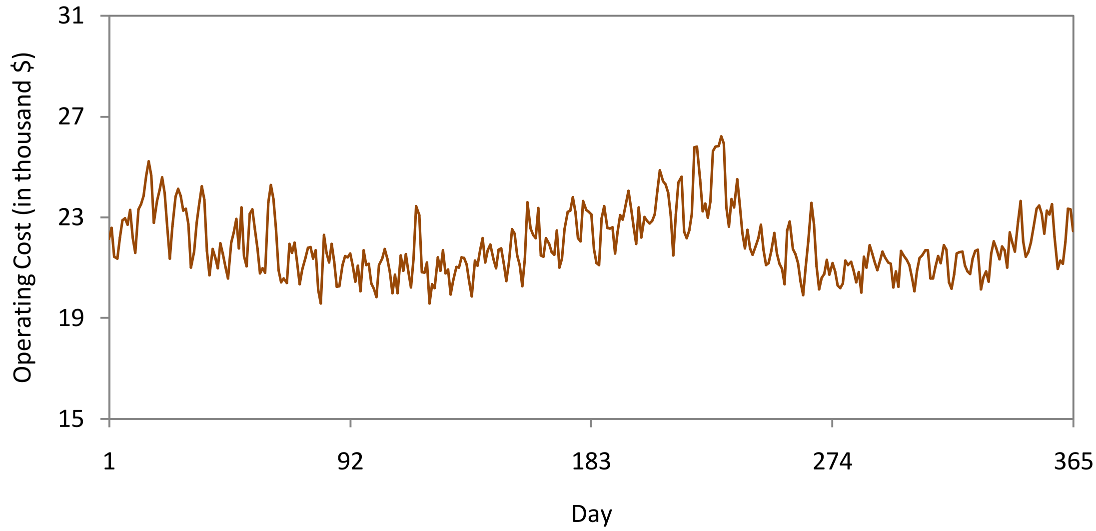

Figure 6.3: Facility 2's Daily Operating Cost

The same procedure is used to compute the manufacturing facilities' annual equivalent cost at different values of the nominal interest rate. Table 6.1 shows the results.

Table 6.1: Sensitivity Report of Annual Equivalences of No Wind Case

r%	Power generating company	Facility	
	AER ($)	AEC_1 ($)	AEC_2 ($)
5%	$51,566,269	$19,678,120	$8,575,899
6%	$51,690,579	$19,770,579	$8,615,463
7%	$51,815,539	$19,863,647	$8,655,285
8%	$51,941,187	$19,957,328	$8,695,367

6.3 With Wind Case

For the remaining cases, two wind farms are included in the power grid. A tax credit of $19 per megawatt of wind power generated is applied in the calculations. Three scenarios are considered as follows:

Case B: Third Party Wind Energy Investment

Case C: Manufacturing Facility Wind Energy Investment

Case D: The Power Generating Company Wind Energy Investment

Any power market participant in the power grid investing in the wind farm pays for the development cost but will receive the salvage value of the machine at the final year of keeping the machine. In addition, an incentive is offered to anyone who owns the wind farm and generates electricity using wind from the beginning of power generation to the final year of owning the wind farm, which is 5 years in this experiment. There are two farms in the power grid. The first wind farm is located on bus 1 and has the maximum capacity of 15 MW while the second wind farm is located on bus 2 and has the maximum capacity of 10 MW. Once again, the following correction models are used throughout the Case with Wind.

For the power generating company

$\widehat{PP}_d = -316247 + 0.263 \cdot PP_d + 53.8 \cdot L_d + 20.3 \cdot W_d$

And for the manufacturing facility

For Facility 1: $\widehat{FC}_{1,d} = 3825 + 0.247 \cdot FC_{1,d} + 4.43 \cdot L_d - 2.28 \cdot W_d$

For Facility 2: $\widehat{FC}_{2,d} = 4194 + 0.046 \cdot FC_{2,d} + 2.25 \cdot L_d - 1.49 \cdot W_d$

6.3.1 Case B: Third Party Wind Energy Investment

In this case, the wind farms are assumed to be owned by a third party. The power company purchases the wind power from the third party. The daily profits of the power generating company are obtained by equations 5.8 and 5.9 while the daily operating costs of the manufacturing facility are obtained by equation 5.10. All equations are described in chapter 5.

The annual equivalences in this case are calculated using the same procedure as in Case No Wind. The annual equivalences of the facility and the power company are given in Table 6.2.

Table 6.2: Sensitivity Report of Annual Equivalences of Case B

$r\%$	Power generating company	Facility	
	AEP ($)	AEC_1 ($)	AEC_2 ($)
5%	$44,561,290	$18,605,879	$8,163,282
6%	$44,608,547	$18,685,465	$8,198,328
7%	$44,655,875	$18,765,565	$8,233,600
8%	$44,703,319	$18,846,185	$8,269,101

Since a third party owns the wind farm, it has to pay the development cost of the wind farm, which is approximately $ 1 million per megawatt. Therefore, the third party pays a total of $ 25 million for two wind farms. It is assumed that the third party will keep the machine for five years. Therefore, a 10-MARCS is used. The value of the machine is assumed to decline according to this depreciation schedule. The salvage value of the machine can be calculated using the depreciation schedule presented in Table 5.1 with a half-year convention is applied to year 5. Thus,

Salvage value = $25M - $25(10% + 18% + 14.4% + 11.52% + 9.22%/2)

= $10,367,500

In this case, the wind power government incentive of $19/MWh is applied. The annual equivalent revenue can be calculated using equations 5.1 and 5.2 In this case, $X_d = TR_d$, then

$$PW = \sum_{d=1}^{1825} \frac{TR_d}{(1+i)^d}$$

$$PW = \$32{,}581{,}191$$

and

$$AER = PW \cdot \left[\frac{i(1+i)^5}{(1+i)^5 - 1}\right]$$

$$AER = \$7{,}551{,}821$$

The annual equivalent revenue of the wind farm is $7,665,186. However, since the third party has paid the investment cost of $25M and is expected to have the salvage value of $10,367,500, the capital recovery cost (CR) of the machine can be obtained using (5.3) given in chapter 5.

At r = 5%, $i = \left(1 + \frac{5\%}{365}\right)^{365} - 1$ = 5.13% compounded annually

$$CR(i) = (\$25M - \$10{,}367{,}500)\left[\frac{i(1+i)^5}{i(1+i)^5 - 1}\right] + i \cdot \$10{,}367{,}500$$

$$CR(i) = \$3{,}923{,}105$$

If the company keeps the wind farm for five years, the third party company pays an annual equivalent cost of $3,923,105. Thus, the annual equivalent worth of the wind farm is

$$AEW = AER - CR$$

= $7,551,821 - $3,923,105

= $3,628,716

The annual equivalent worth of the wind farm when owned by the third party is $3,628,716 at r = 5%. Table 6.3 shows the AEW for different values of r.

Table 6.3: Annual Equivalent Worth of the Wind Power Plant

r%	AEW
5%	$3,628,716
6%	$3,456,350
7%	$3,280,941
8%	$3,102,455

6.3.2 Case C: Manufacturing Facility Wind Energy Investment

In this case, the manufacturing facilities own the wind farms. For the power generating company, the daily profits of the company remain the same as Case B but the power company buys wind power from the manufacturing facilities instead of from the third party company.

When calculating the total annual equivalent cost of the facilities, the capital recovery cost of the wind farm has to be included. The manufacturing facility's daily operating costs are calculated using equation 5.14 in chapter 5. Using equations 5.1 and 5.2, the annual equivalent operating cost of the Facility 1 is \$ 14,078,720 and the capital recovery cost of owning the wind farm is

$$CR(i) = (\$15M - \$6{,}220{,}500)\left[\frac{i(1+i)^5}{i(1+i)^5 - 1}\right] + i \cdot 6{,}220{,}500$$

$$CR(i) = \$2{,}353{,}863$$

Therefore, the total annual equivalent cost of the Facility 1 is \$ 14,078,720 + \$2,353,863 = \$16,432,583. The complete calculation of annual equivalences of this case is presented in Table 6.4.

Table 6.4: Sensitivity Report of Annual Equivalences of Case C

$r\%$	Power generating company	Facility	
	AEP ($)	AEC_1 ($)	AEC_2 ($)
5%	$44,561,290	$16,432,583	$7,253,467
6%	$44,608,547	$16,615,576	$7,361,408
7%	$44,655,875	$16,800,909	$7,470,822
8%	$44,703,319	$16,988,607	$7,581,723

The investment of the wind power is calculated the same as in Case B but the annual equivalent worth of the wind farms is calculated separately because they are owned by two different manufacturing facilities. The annual equivalent worth power investment at facility 1 is shown in Table 6.5.

Table 6.5: Annual Equivalent Worth of Wind Power at each Bus

$r\%$	Wind Bus 1	Wind Bus 2
5%	$2,173,296	$1,455,419
6%	$2,069,889	$1,386,461
7%	$1,964,656	$1,316,285
8%	$1,857,577	$1,244,878

6.3.3 Case D: The Power Generating Company Wind Energy Investment

The power company owns two wind farms, 15MW at bus 1 and 10 MW at bus 2. In this case, the power generating company's daily profits are calculated by equations (5.15) and (5.16) and the manufacturing facility's daily operating costs are calculated by equation (5.17) in chapter 5. Similar to previous cases, the annual equivalences of Case D are presented in Table 6.6

Table 6.6: Sensitivity Report of Annual Equivalences of Case D

$r\%$	Power generating company	Facility	
	AEP ($)	AEC_1 ($)	AEC_2 ($)
5%	$48,190,006	$18,605,879	$8,163,282
6%	$48,064,898	$18,685,465	$8,198,328
7%	$47,936,816	$18,765,565	$8,233,600
8%	$47,805,775	$18,846,185	$8,269,101

6.4 Summary of the Economic Analysis

For comparison purposes, the interest rate of 6% compounded daily is used throughout the analysis. The summary of annual equivalences of the power generating company and the manufacturing facility at different scenarios is presented in Table 6.7.

Table 6.7: Annual Equivalences of all Cases

Case	Power generating company	Facility	
	AEP ($)	AEC_1 ($)	AEC_2 ($)
A	$51,690,579	$19,770,579	$8,615,463
B	$44,608,547	$18,685,465	$8,198,328
C	$44,608,547	$16,615,576	$7,361,408
D	$48,064,898	$18,685,465	$8,198,328

For the power generating company and the manufacturing facility, Case A is again the benchmark scenario that is used for comparison with other scenarios. From the results in Table 6.11, the manufacturing facility seems to benefit from wind power, and this is reflected by the annual cost, which is reduced compared to Case A.

6.5 Economic Analysis of the Wind Farm

In this section, the economic analysis of standalone wind farm is performed to justify the assessment of wind farm investment. A more detailed sensitivity analysis of wind capacity factor and incentives is performed.

6.5.1 Sensitivity Analysis on Wind Capacity Factor

With the current wind power profile, a wind farm investor will never lose money at any interest rates. A sensitivity analysis is performed by reducing the capacity factor, which is 40%, by 5%, 10%, 15%, 20%, and 30%. The sensitivity analysis is presented in Table 6.8.

Table 6.8: Annual Equivalences of Wind Electric Power

Capacity factor Reduction	New capacity factor	AER ($)	AEC ($)	AEW ($)
0	40.00%	$7,588,413	$4,132,062	$3,456,350
5%	36.74%	$7,225,676	$4,132,062	$3,093,614
10%	34.80%	$6,854,704	$4,132,062	$2,722,641
15%	32.87%	$6,486,800	$4,132,062	$2,354,737
20%	30.94%	$6,113,306	$4,132,062	$1,981,243
30%	27.07%	$5,370,150	$4,132,062	$1,238,088

From Table 6.8, the annual equivalent revenues are decreased as the wind capacity factor decreases. However, the annual equivalent cost is unchanged throughout all cases because the annual equivalent cost in this case is the cost of owning the wind farm, or in other words, the capital recovery cost and can be considered a fixed cost. Figure 6.4 displays the scenarios of the wind power capacity factor.

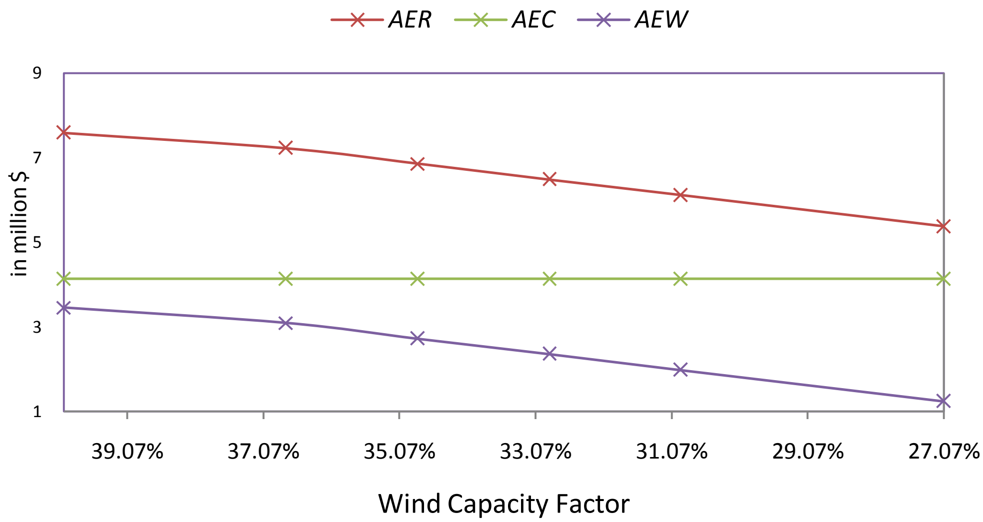

Figure 6.4: Sensitivity Results of the Wind Power Capacity

Even though wind power capacity drops 30% from the current point, the wind farm still generates profits for the investor.

6.5.2 The Break-Even Point of Wind Power Capacity Factor

In this experiment, the current wind capacity factor is around 40% of its possible maximum capacity. The break-even point of wind capacity factor will answer the question of how much minimum wind capacity factor is needed in order to maintain a preferable wind farm investment.

The maximum capacity of 25MWh wind farm for 5 years is calculated as

$$25MWh \times 24h \times 365days \times 5year = 1{,}095{,}000 \text{ MW}$$

The study has found that, at a capacity factor of 26%, the annual equivalent worth of wind farm becomes negative, but for a capacity factor of 27%, the annual equivalent of the wind farm is positive when the incentive is assumed to be zero. The annual equivalent worth with different capacity factors is shown in Table 6.9.

Table 6.9: Annual Equivalent Worth of Wind Farm with Capacity Factor

Capacity Factor	AEW
26%	($87,377)
27%	$64,044

Using linear interpolation, the capacity factor at the break-even point is 26.58%. This means the wind farm needs at least 26.58% of the capacity factor (or 291,051 MW annually) to start generating profit. Figure 6.5 illustrates the sensitivity results of the wind power capacity factor.

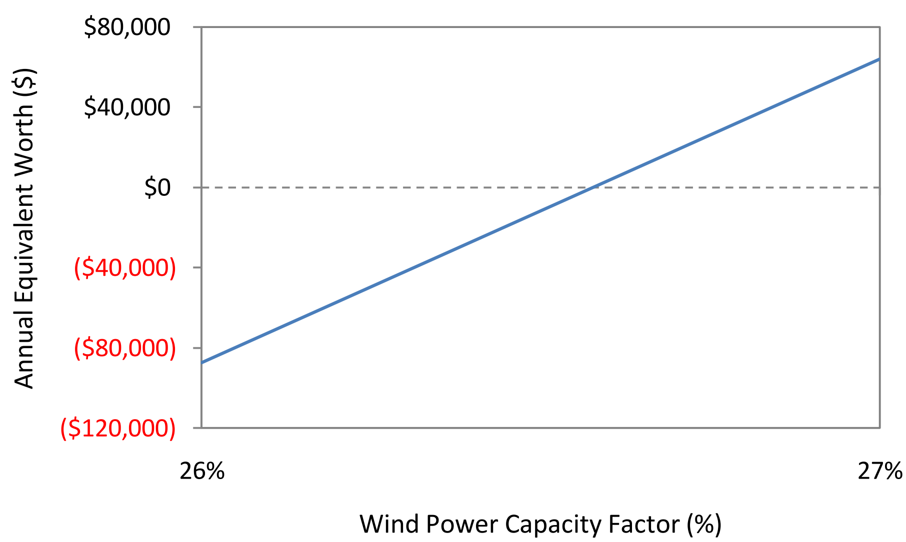

Figure 6.5: Sensitivity Results of the Wind Power Capacity Factor

6.5.3 Break-Even Point on Incentives

For a third party, if no incentive is applied, the annual equivalent worth still remains positive. This means the investor still benefits from the investment even though there is no outside financial promotion. Table 6.10 shows a comparison of the annual equivalent worth with and without an incentive.

Table 6.10: Annual Equivalences of a Third Party

Scenario	AEW
Incentive	\$3,456,350
No incentive	\$1,794,306

With no incentive, the annual equivalent worth is reduced approximately 50%, but the wind farm still generates profits for the investor. However, a more detailed sensitivity analysis on the incentive will be performed. The objective of this section is to determine the break-even point of the incentive, or in other words, what is the minimum incentive that makes the wind farm investment profitable. As in 6.3.2, the analysis shows that, at capacity factor of 26% of wind farm without an incentive, the annual equivalent worth of wind farm is negative. Therefore, the wind farm with a capacity factor of 26% is a reference to obtain the break-even incentive. Once again, the linear interpolation technique is used to compute the incentive. The annual equivalent worth of the wind farm with different incentives is shown in Table 6.11, and the sensitivity result of the incentive is presented in Figure 6.6.

Table 6.11: Annual Equivalent Worth of Wind Farm with Incentive

Incentive ($/MWh)	*AEW* ($)
$0	($87,377)
$1	($28,557)
$2	$30,262

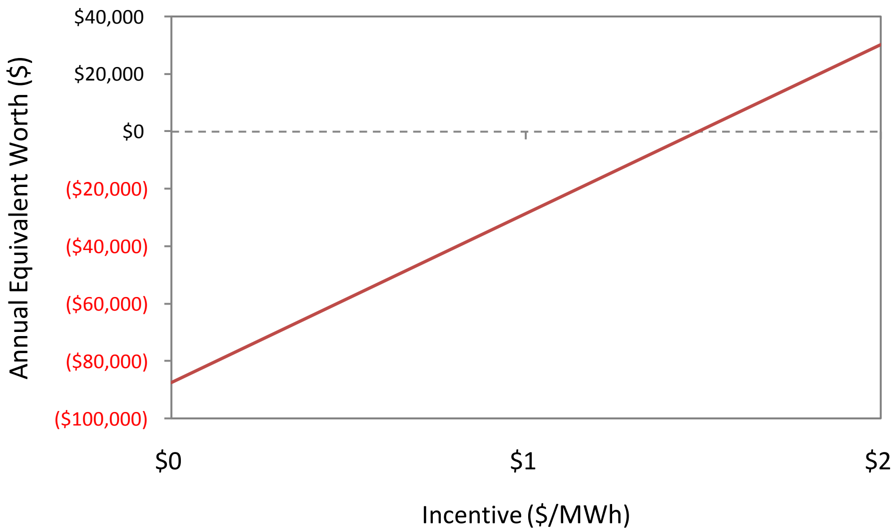

Figure 6.6: Sensitivity Results of the Incentive

Using the linear interpolation technique, the break-even point of the incentive is $1.49/MWh. Therefore, at a wind power capacity of 26%, an incentive as low as $1.49/MWh would make the wind farm project justifiable.

6.6 Summary of Sensitivity Analysis

This chapter presents the sensitivity analysis of the wind power capacity factor and incentives. The results show that, at the current point, investing in wind electric power is beneficial for an investor. A wind farm itself is quite productive because it requires a capacity factor of only 26.68% to generate turnover. Wind data used in this experiment accounts for 40% of the wind farm's maximum capacity and, with the incentive, dropping 30% from this current point still makes wind farm investment profitable according to the results in Table 6.12.

Technically, the location of the wind farm has to be investigated at an early stage. That is, the site must have a minimum annual average wind speed in the neighborhood of 4.92 m/s to 5.8 m/s or approximately 5% to 10% of the maximum capacity. More information can be found at [52]. In addition, wind farm investment is a very attractive project since it entails a lower maintenance cost but provides benefits immediately after installation.

6.7 The Favorable Size of Wind Farm when the Facilities Make an Investment

In section 6.2, the results show that manufacturing facilities benefit from a reduction in annual cost when wind electric power is connected to the power grid. In this section, variations in wind farm size are examined to justify how large of a wind farm size the facility should invest in so that it can economically reduce its annual cost. The wind farm's revenue and capital recovery cost vary according to wind farm size. The combinations of wind farm sizes on buses 1 and 2 are observed. A summary of wind farm sizes and associated annual costs is presented in Table 6.12.

Table 6.12: Annual Cost of the Facility with Different Wind Farm Sizes

Wind Farm Size (MW)		Manufacturing Facility's Cost ($)		
BUS 1	BUS 2	AEC_1	AEC_2	$TAEC$
5	5	$18,117,228	$7,543,068	$25,660,296
5	10	$18,075,343	$6,803,230	$24,878,573
10	5	$17,347,953	$7,527,740	$24,875,693
10	10	$17,310,024	$6,794,833	$24,104,856
15	5	$16,593,807	$7,510,236	$24,104,043
15	10	$16,615,576	$7,361,408	$23,976,984

From Table 6.12, the best option of Facility 1 is to invest in 15 MW and Facility 2 to invest in 5 MW whereas the best option of Facility 2 is that both Facilities invest in 10 MW each. However, in this research, both Facilities are owned by the same owner. Therefore, the best option for the investor is to invest in a 15 MW and 10 MW wind farm on bus 1 and bus 2, respectively, because this investment provides the lowest total annual equivalent cost, that is, $23,976,984 annually for both manufacturing facilities.

CHAPTER 7

CONCLUSION AND FUTURE RESEARCH DIRECTIONS

In this research, system operating models for a manufacturing facility and an economic analysis of a wind farm investment are introduced. Two operating models, SO-A and SO-B, are developed for a manufacturing facility to replicate the interaction between the manufacturing facility's energy usage and a power network system. The SO-A model is a more accurate representation of the system, but it is inconvenient for use in long-term studies. The SO-B model is much easier to solve, but the output differs from the output of the SO-A model. Therefore, a correction model is developed for estimating the output of the SO-A using the output of the SO-B model. In addition, formulations for a wind farm investment are formulated, and economic analyses are performed under different scenarios, where the scenario "No Wind" is used as a benchmark for the cases "With Wind".

In solving a system consisting of 5 buses, 4 generators, 2 wind farms, and 2 manufacturing facilities, the results showed that wind power investment provides economic benefits to the manufacturing facilities in either purchasing or generating part of their energy using wind power. Investing in a wind farm project is preferable for the manufacturing facility in terms of the annual equivalent cost reduction. Wind farm sizes of 15 MW and 10 MW are shown to be economical because investment in wind farms of these sizes allows the manufacturing facility to pay the lowest total annual equivalent cost. For the power generating company, including wind power in the power network reduces the company's annual profit. If the power system must include a wind farm, then the best alternative for the power generating company is to own the wind farm.

Furthermore, the wind farm generates profits even without the production tax credit incentive when considering a wind capacity factor of at least 26.58%, equivalent to a wind power capacity of 291,051 MW annually. In the study, the incentive plays an important role in wind farm investment because it accounts for 22% of the wind farm's total annual equivalent revenue and approximately 50% of the wind farm's total annual equivalent profit. The study also shows that an incentive of $1.49 per MWh and wind capacity factor of 26% makes wind investment preferable.

In this dissertation the wind power and load are assumed to be deterministic. Therefore, future research should model the wind power and load as stochastic processes to represent the uncertain, and stochastic programming could be considered for modeling the interaction of market participants. Moreover, neither generation nor transmission expansion has been assumed. In future research, new generation capacity and transmission expansion can be modeled.

Another extension to this research is the size of the power network. In this study, it is relatively small. Thus, developing a solution algorithm for solving a larger power system problem is a possible research direction. In addition, start-up costs as well as maximum and minimum on and off generation constraints are ignored. Including unit commitment operating constraints presents an interesting area for future research.

Furthermore, the manufacturing facilities are assumed to produce just one product, and only inventory constraints are considered. In addition, the manufacturing facilities' demands are fixed for all periods of this study. Finally, maintenance scheduling is assumed to be tentative. Hence, more manufacturing facilities that produce several products and maintenance scheduling of facilities can also be considered. Dynamic demands can be included to make the model more realistic.

Finally, for the wind farm, borrowing and maintenance costs were not taken into account to avoid additional complexity. Other government incentives [52] such as net metering, renewable-energy credits, and installation tax credits were also ignored. In addition, some states such as Texas receive financial promotion from the Department of Agriculture [53]. Therefore, in future research, models that include more details of the wind farm's economic aspects can be developed to ascertain the more detail on wind farm investment.

REFERENCES

[1] Energy Policy Act of 2005

[2] American Wind Energy Association (AWEA)

http://www.awea.org/faq/wwt_costs.html#How%20much%20does%20wind%20energy%20cost

[3] AWEA *20% Wind Energy by 2030: Wind, Backup Power, and Emissions*

http://www.awea.org/pubs/factsheets/Backup_Power.pdf

[4] Energy, T. D. (2008). *20% Wind Energy by 2030.*

[5] PJM - Training

http://pjm.com/training/~/media/training/core-curriculum/ip-gen-101/20050713- gen-101-lmp-overview.ashx

[6] Spees, K. & Lave, L. (2007). *Impacts of Responsive Load in PJM: Load Shifting and Real Time Pricing*. Carnegie Mellon University, Carnegie Mellon Electricity Industry Center

[7] Faruqui, A., Hledik, R., Newell, S., & Pfeifenberger, J. (2007). *The Power of Five Percent*. The Brattle Group

[8] Brown,G.B., Katz,W.R., & Murphy,H.A. (1984). *Time Series Models to Simulate and Forecast Wind Speed and Wind Power*. Journal of Climate and Applied Meteorology.

[9] Sideratos, G., & Hatziargyriou, N. D. (2007). *An Advanced Statistical Method for Wind Power Forecasting*. IEEE Transaction on Power Systems .

[10] Contaxis, G. C., & Kabouris, J. (1991). *Short Term Schedule in A Wind/Diesel Autonomous Energy System*. Transactions on Power System

[11] Patel, M. R. (1999). *Wind and Solar Power Systems.* Boca Raton,FL: CRC Press.

[12] S. M. Chan, D.C. Powell, M. Yoshimura, & D.H. Curtice.(1983). *Operations Requiremnts of Utilities with Wind Power Generation*. IEEE Trans. On Power Apparatus and Systems.

[13] Talukda, S. N. & Wu, F. F. (1981). *Computer-Aided Dispatch for Electric Power System*. Proceeding of the IEEE, Volume 69, No.10, pp. 1212-1231, October 1981

[14] Megahed, R. C., Abou-Taleb, N., Iskandrani, M., & Moussa, A. (1977). *A Modified Method for Solving Economic Dispatching Problem*. IEEE Transaction on Apparatus and Systems, Volume PAS-96, No.1, pp. 124 133, January/February 1977

[15] Irving, M. R. & Sterling, J. H. (1983). *Economic Dispatch of Active Power with Constraint Relaxation*. IEEE Proceedings, Volume 130, Pt. C, No. 4, July 1983

[16] Mota-Palomino, R. & Quintana, V. H. (1984). *A Penalty Function – Linear Programming Method and Solving Power System Constrained Economic Operation Problems*. IEEE Transaction on Apparatus and Systems, Volume PAS-103, No. 6, pp. 1414-1422, June 1984

[17] Waight, J. G., Bose, A., & Sheble, G. B. (1981). *Generation Dispatch with Reserve Margin Constraints Using Linear Programming*. IEEE Transaction on Apparatus and Systems, Volume PAS-100, No. 1,pp.252-258, January 1981

[18] Maria, G. A. & Findlay, J. A. (1987). *A Newton Optimal Power Flow Program for Ontario Hydro EMS*. IEEE Transaction on Apparatus and Systems, Volume PWRS-2, No. 3, pp.579-584, August 1987

[19] Lee, K. Y., Ortiz, J. L., Mohtadi, M. A., & Park, Y. M. (1988). *Optimal Operation of Large-Scale Power System*. IEEE Transaction on Power Systems, Volume 3, No. 2, pp.413-420, May 1988

[20] Contaxis, G. C., Papadias, B. C., & Delkis, C. (1983). *Decoupled Power System Security Dispatch*. IEEE Transaction on Apparatus and Systems, Volume PAS-102, No.9, pp.3049-3056, September 1983

[21] Burchett, R. C., Happ, H. H., & Wirgu, K. A. (1982). *Large-Scale Optimal Power Flow*. IEEE Transaction on Apparatus and Systems, Volume PAS-101, No. 10, pp. 3722 3732, October 1982

[22] Bacher, R. & Van Meeteren, H. P. (1988). *Real-Time Optimal Power Flow In Automatic Generation Control*. IEEE Transaction on Power Systems, Volume 3, No. 4, pp.1518-1529, November 1988

[23] Talukda, S. N., Giras, T. C., & Kalyan, V. K. (1983). *Decompositions for Optimal Power Flow*. IEEE Transaction on Apparatus and Systems, Volume PAS-102, No. 12, pp.3877-3884, December 1983

[24] Su, C. & Chiou, G. (1997). *A Fast-Computation Hopfield Method to Economic Dispatch of Power Systems*. IEEE Transaction on Power Systems, Volume 12, No. 4, pp. 1759-1764, November 1997

[25] Lee, T. H., Thorne, D. H., & Hill, E. F. (1980). *A Transportation Method for Economic Dispatching – Application and Comparison*. IEEE Transaction on Apparatus and Systems, Volume PAS-99, No. 6, pp.2373-2385, November/December 1980

[26] Galloway, S., Bell, G., Burt, J., McDonald, J., & Siewierski, T. (2006). *Managing The Risk Of Trading Wind Energy In A Competitive Market*. IEE Proc.-Gener. Transm. Distrib., Volume 153, No. 1, pp. 106-114, January 2006

[27] Pinson, P., Chevallier, C., & Kariniotakis, G. N. (2007). *Trading Wind Generation From Short-Term Probabilistic Forecasts of Wind Power*. IEEE Transaction on Power Systems. pp. 1-9, February 2007

[28] Bathurst, G. N., Weatherill, J., & Strbac, G. (2002).*Trading Wind Generation in Short Term Energy Market*. IEEE Transaction on Power Systems. , Volume 17, No. 3, pp. 782-789, August 2002

[29] Pinson, P., Chevallier, C., & Kariniotakis, G. N. (2004). *Optimizing Benefits from Wind Power Participation in Electricity Markets using Advanced Tools for Wind Power Forecasting and Uncertainty Assessment*. In Proc. of the 2004 EWEC Conference, London, November 2004

[30] Holttinen, H. (2005). *Optimal Electricity Market for Wind Power*. Energy Policy 33 (2005) 2052-2063

[31] Usaola, J. & Angarita, J. (2007). *Bidding Wind Energy under Uncertainty*. IEEE Conference, pp. 754-759, 2007

[32] Matevosyan, J. & Soder, L. (2006). *Minimization of Imbalance Cost Trading Wind Power on the Short-Term Power Market*. IEEE Transaction on Power Systems, Volume 21, No. 3, August 2006

[33] AWEA : *What are the environmental benefits of wind power?* http://www.awea.org/faq/wwt_environment.html#What%20are%20the%20environmental%20benefits%20of%20wind%20power

[34] World Wind Energy Report 2009

www.wwindea.org/home/images/stories/worldwindenergyreport2009_s.pdf

[35] Wind Turbine. http://en.wikipedia.org/wiki/Wind_turbine

[36] Wind Farm. http://en.wikipedia.org/wiki/Wind_farm

[37] 9 of the World's Most Amazing Wind Farms

http://webecoist.com/2009/04/10/9-of-the-worlds-most-amazing-wind-farms/

[38] U.S. Wind Resource Ever Larger Than Previously Estimated.

http://www.awea.org/newsroom/releases/02-18-10_US_Wind_Resource_Larger.html

[39] Net Metering: Entergy.

http://www.entergy-neworleans.com/your_business/net_metering.aspx

[40] Bazaraa, M.J.,Jarvis, J.J., & Sherali, H.D. (1993). *Nonlinear Programming Theory and Algorithms 2nd Edition.* United States: John Wiley & Sons,Inc.

[41] Marcotte, P., & Savard, G. (2005). *Bilevel Programming:A Combinatorial Perspective.* In D. Avis, A. Hertz, & O. Marcotte, Graph Theory and Combinatorial Optimization (pp. 191-217). Montreal, Canada: GERAD.

[42] Perris, M.C. & Pang, J. S. (1997). *Engineering and Economic Applications of Complementarity Problems.* Society for Industrial and Applied Mathematics Volume 39, No.4, pp 669-713, December 1997

[43] Leyffer, S. (2003). *Mathematical Programs with Complementarity Constraints.* SIAG/OPT Views and News Volume 4, No.1, pp 15-18, April 2003

[44] Park, C. S., Valenzuela, J. F., Halpin, M., Sozer, S.,& Kaymaz, P. (2006). *Pricing Transmission Congestion in Electric Power Network*.

[45] National Weather Service Forecast Office

http://www.erh.noaa.gov/pbz/hourlyclimate.htm

[46] WinWinD. http://www.winwind.com/offering/1-mw/#detailed-data (winwind)

[47] Reuters Article on CO2 Regulation

http://www.reuters.com/article/idUSN1529571120080916?pageNumber=1

[48] Period to build wind power. http://www.gfeswind.com/faq.html

[49] Period to build a power plant

http://en.wikipedia.org/wiki/Economics_of_new_nuclear_power_plants

[50] Park, C. S. (2010). *Contemporary Engineering Economics 5th*. United States: Prentice Hall

[51] 10 Steps in Building a Wind Farm

http://www.fishermensenergy.com/dms/showfile.php?id=3

[52] Government incentives

http://science.howstuffworks.com/environmental/green-science/wind-power8.htm

[53] State Energy Conservation Office: Wind Energy Incentives

http://www.seco.cpa.state.tx.us/re_wind-incentives.htm