EFFECTS OF LOW CARBON EMISSION GENERATION AND ENERGY STORAGE ON GREENHOUSE GAS EMISSIONS IN ELECTRIC POWER SYSTEMS

A Dissertation by

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The following faculty members have examined the final copy of this dissertation for form and content, and recommend that it be accepted in partial fulfillment of the requirement for the degree of Doctor of Philosophy with a major in Electrical Engineering.

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DEDICATION

To my parents and my sisters
ACKNOWLEDGMENTS

My deepest gratitude goes to my mentor, Dr. Ward T. Jewell. This dissertation would not have been finished without his guidance, supervision, and encouragement. Dr. Jewell always provided me with excellent sources of knowledge. I would like to thank him for inspiring me to pursue graduate degrees in the field of power engineering.

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ABSTRACT

The electric power industry produces substantial amounts of carbon dioxide (CO₂) as well as other greenhouse gas (GHG) emissions. Recent GHG regulations along with renewable portfolio standards encourage the integration of low carbon emission generation into the electric power system and, as a result, drastically affect operations, design, and planning of the electric power system. Extensive studies on this issue, therefore, are important.

This dissertation first discusses renewable standards and policies in the United States (U.S.), which include renewable portfolio standards. Current U.S. electricity markets for renewable generators such as wind generation resources and solar power plants are investigated. This research analyzes several factors that affect an electric power system due to the integration of these low carbon generators.

The dissertation then develops system operating cost models for renewable generation and energy storage. With consideration of CO₂ emission costs, the system operating cost model for a fossil-fired generating unit is presented and discussed.

By using optimal power flow, security-constrained optimal power flow, time step series input, and the CO₂ emissions incorporated objective function, this dissertation develops a new methodology to study the effects of low carbon emission generation and energy storage on GHG emissions in electric power systems.

A number of relevant study cases are presented. The cost models and methodology are applied to the study cases. The IEEE 24 bus Reliability Test System (IEEE RTS) is used as the sample test system. This system has been modified to include additional generation fuels to study the amount of various CO₂ emissions.
Simulation results, including system operating costs, total emissions, economic dispatch, and locational marginal prices, are presented and discussed. This dissertation addresses two major issues: system operating cost and system reliability. Finally, conclusions are drawn and discussed, and future work is recommended. Conclusions include:

- The integration of renewable generation reduces CO$_2$ but emissions of reserve units must be considered.
- The integration of low carbon emission generation tends to reduce system operating cost. The system operator still must consider the operating cost of renewable generators and reserve fossil-fired generators.
- The change of emissions and system operating cost are not proportional to the additional capacity of renewable generation installed due to complexities of an electric power system.
- The system operating cost model for renewable generation is able to properly represent the special characteristics of these low carbon emission generators. The proposed operating cost model for energy storage can also be used to verify its effects on overall system cost and emissions.
- The developed methodology can be used to investigate an electric power system with integrated renewable generation and energy storage. It has the ability to consider several factors and unique characteristics of renewable generation, energy storage, and the transmission system.
- Generation output profiles of low carbon emission generation significantly affect total CO$_2$ emissions of an electric power system.
• Solar’s higher capacity credit reduces the need for other reserve units, which can lower costs and emissions, and produces significantly different results between solar and wind generators.

• CO₂ prices have no effect on the operation of installed wind and solar generation. A price on CO₂ does, however, provide an incentive to build new solar and wind generators, because increased generating costs from fossil-fired generators results in higher payments to renewable generators.
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<tbody>
<tr>
<td>5.42</td>
<td>Marginal price with 300 MW installed solar in case 8.</td>
<td>79</td>
</tr>
<tr>
<td>5.43</td>
<td>Changes in system operating cost in case 9.</td>
<td>80</td>
</tr>
<tr>
<td>5.44</td>
<td>Changes in CO₂ emissions in case 9.</td>
<td>81</td>
</tr>
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<td>5.45</td>
<td>Generation dispatch in case 9.</td>
<td>81</td>
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<tr>
<td>5.46</td>
<td>Changes in system operating cost in case 10.</td>
<td>82</td>
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<tr>
<td>5.47</td>
<td>Changes in CO₂ emissions in case 10.</td>
<td>83</td>
</tr>
<tr>
<td>5.48</td>
<td>System operating cost in case 9 and case 10.</td>
<td>83</td>
</tr>
<tr>
<td>5.49</td>
<td>Total CO₂ emissions in case 9 and case 10.</td>
<td>84</td>
</tr>
<tr>
<td>5.50</td>
<td>Changes in system operating cost in case 11.</td>
<td>85</td>
</tr>
<tr>
<td>5.51</td>
<td>Changes in CO₂ emissions in case 11.</td>
<td>85</td>
</tr>
<tr>
<td>5.52</td>
<td>System operating cost in case 2 and case 11.</td>
<td>86</td>
</tr>
<tr>
<td>5.53</td>
<td>Total CO₂ emissions in case 2 and case 11.</td>
<td>86</td>
</tr>
<tr>
<td>5.54</td>
<td>Generation dispatch for coal-fired power plants in case 1.</td>
<td>91</td>
</tr>
<tr>
<td>5.55</td>
<td>Generation dispatch for gas-fired power plants in case 1.</td>
<td>92</td>
</tr>
<tr>
<td>5.56</td>
<td>CO₂ emissions in a zero CO₂ price system.</td>
<td>94</td>
</tr>
<tr>
<td>5.57</td>
<td>CO₂ emissions in a $50/ton CO₂ price system.</td>
<td>94</td>
</tr>
<tr>
<td>5.58</td>
<td>System operating cost for zero CO₂ price system for 24-hour period.</td>
<td>98</td>
</tr>
<tr>
<td>5.59</td>
<td>System operating cost for given CO₂ price system for 24-hour period.</td>
<td>98</td>
</tr>
<tr>
<td>5.60</td>
<td>Locational marginal price in case 1.</td>
<td>100</td>
</tr>
</tbody>
</table>
Chapter 1 provides an introduction to this dissertation. Section 1.1 presents background information about greenhouse gas emissions and renewable generators in the U.S. Section 1.2 outlines the objectives and scope of work of the dissertation. Finally, section 1.3 discusses the organization of this dissertation.

1.1 Background

1.1.1 Greenhouse Gas Emissions and Electricity Generation

Widely considered a major cause of climate change, greenhouse gases (GHGs) permit sunlight to move through the earth’s atmosphere and absorb infrared radiation or heat that is typically re-radiated back into space but is trapped in the atmosphere. Some GHGs occur in nature, and others are produced by human activities. The GHGs that are emitted into the earth’s atmosphere due to human activities include carbon dioxide (CO$_2$), methane (CH$_4$), ozone (O$_3$), and nitrous oxide (N$_2$O).

As one of the most important GHGs, CO$_2$ contributes the most significant amount of all GHG emissions. In 2006, CO$_2$ accounts for 84.8 percent of total GHG emissions in the U.S. [1]. The burning of trees, solid waste, and fossil fuels, and some chemical processes all release CO$_2$ into the atmosphere.

The combustion of fossil fuels, however, is the most dominant activity that emits CO$_2$ into the earth’s atmosphere. It is the largest source of CO$_2$ emissions as well as total GHG emissions. In 2006, the burning of fossil fuels emitted 5,637.9 teragrams of carbon dioxide equivalents (Tg CO$_2$ Eq.) countrywide, which represents 94.2 percent and 79.9 percent of CO$_2$ emissions and total U.S. GHG emissions, respectively [1]. Fossil fuel combustion is an essential
process in several economic sectors: transportation, industrial, commercial, residential, and electricity generation.

Largely utilizing the combustion of fossil fuels, electricity generation produces substantial amounts of CO$_2$ emissions and is considered the human activity that is responsible for the largest single amount of both CO$_2$ emissions and total GHG emissions in the U.S. The electric power industry represents 33 percent of total GHG emissions generated in the U.S. in 2006 and also accounts for 38.9 percent of CO$_2$ emissions in the same year [1]. Figure 1.1 presents the CO$_2$ emissions due to fossil fuel combustion by each economic sector in the U.S. during 2000–06. According to the figure, electricity generation is clearly leading other economic sectors in CO$_2$ emissions in the past years. Therefore, it can be concluded that the electric power industry plays a crucial role in GHG emissions.

![Graph showing CO$_2$ emissions by sector](image)

Figure 1.1. CO$_2$ emissions due to fossil fuel combustion by U.S. economic sectors (2000–06) [1].

### 1.1.2 Renewable Generation in the U.S.

Unlike traditional fossil fuel energy sources, renewable energy uses fuels that are able to be regenerated in a relatively short period of time, and its fuels are abundantly available in nature.
According to the Energy Information Administration (EIA), about 7 percent of U.S. energy consumption in 2007 is from renewable energy. While the nation consumed total energy of 101.605 quadrillion BTU in 2007, 6.830 quadrillion BTU was supplied from renewable generation resources [2]. Figure 1.2 shows the U.S. total energy consumption by energy source in 2007.

![Fossil Fuels (85%), Nuclear (8%), Renewable (7%), Electricity Net Imports (0.1%)](image)

**Figure 1.2. U.S. energy consumption by source in 2007.**

Electricity generation from renewable energy accounted for 351 billion kilowatt hours in the year 2007 [3]. Sources of renewable energy include wind, solar, biomass, geothermal, and hydroelectric. The U.S. electricity net generation from renewable energy in 2007 by source is shown in Figure 1.3, which indicates that hydroelectric power dominates other renewable resources in electricity generation, representing about 71 percent of the U.S. electricity net generation from renewable sources. Biomass is the second largest renewable source in U.S. electricity net generation, representing 16 percent. Wind power plants represent 9 percent, while geothermal and solar energy account for 4 percent and 0.17 percent, respectively.
Except for electricity generation from hydroelectric power, the overall electricity net generation from other renewable resources has been increasing in recent years. Global awareness of climate change together with GHG regulations and renewable policies have strongly encouraged the utilization of renewable generation in the U.S.

Figure 1.4 presents the electricity net generation from renewable generation during 2003–07. According to Figure 1.4, the electricity net generation from wind has dominantly increased in the past years, while a slight increase in net generation from biomass is observed. There is no significant change in electricity net generation from geothermal and solar energy.
Renewable generation must be considered in terms of the amount of energy produced, as well as capacity, or the ability to serve load when needed, which is measured in megawatts (MW). Figure 1.5 summarizes the net summer capacities from renewable generation during 2003–07. According to this figure, the net summer capacity of wind generation is significantly increasing. However, there is only a slight change in the summer capacity of other resources.

According to the EIA, five states had significant capacities of solar generation in the summer of 2007. Table 1.1 shows net summer capacity of solar/photovoltaic (PV) generation of these five states. The state of California is the national leader in net summer capacity of solar generation resources, with 403 MW, while Nevada is the second ranked with 78 MW of solar capacity [3]. The other three states, Arizona, Colorado, and Washington, account for 9, 8, and 1 MW, respectively, of solar capacity in 2007 [3].
TABLE 1.1

NET SUMMER CAPACITY OF SOLAR/PV IN 2007 BY STATE [3]

<table>
<thead>
<tr>
<th>Rank</th>
<th>State</th>
<th>Net Summer Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>California</td>
<td>403</td>
</tr>
<tr>
<td>2</td>
<td>Nevada</td>
<td>78</td>
</tr>
<tr>
<td>3</td>
<td>Arizona</td>
<td>9</td>
</tr>
<tr>
<td>4</td>
<td>Colorado</td>
<td>8</td>
</tr>
<tr>
<td>5</td>
<td>Washington</td>
<td>1</td>
</tr>
</tbody>
</table>
Although solar energy represents both the least electricity generation and system capacity of all renewable resources due to its high cost, it has high potential for being an important energy source in states where abundant solar resources are available, especially in the Southwest. The U.S. Department of Energy (DOE) has created the Solar America Initiative (SAI) program to support the development of solar technology in order to achieve the competitive cost of solar energy by 2015 [4].

With abundant wind resources in the western portion of the state, Texas has provided the nation’s most significant capacity for wind generation resources. In 2007, Texas had 4,006 MW of wind capacity and generated a total of 8.1 billion kilowatt hours from wind [3]. In the same year, the state of California had 2,318 MW of wind capacity, the second largest capacity of wind power in the country. The nation’s top fifteen states in 2007 net summer capacity of wind generation resources are summarized in Table 1.2.

<table>
<thead>
<tr>
<th>Rank</th>
<th>State</th>
<th>Net Summer Capacity (MW)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Texas</td>
<td>4006</td>
</tr>
<tr>
<td>2</td>
<td>California</td>
<td>2318</td>
</tr>
<tr>
<td>3</td>
<td>Washington</td>
<td>1165</td>
</tr>
<tr>
<td>4</td>
<td>Minnesota</td>
<td>1136</td>
</tr>
<tr>
<td>5</td>
<td>Iowa</td>
<td>1134</td>
</tr>
<tr>
<td>6</td>
<td>Colorado</td>
<td>1064</td>
</tr>
</tbody>
</table>

**TABLE 1.2**

TOP FIFTEEN STATES IN NET SUMMER CAPACITY OF WIND IN 2007 [3]
### Objective and Scope of This Work

The purpose of this dissertation is to study how low carbon emission generators, especially renewable generators, and energy storage affect CO\(_2\) emissions. This dissertation focuses on two different areas: system dispatch and operating cost, and system reliability. The objectives of this dissertation include the following:

- To investigate how current electricity markets treat energy from renewable generation resources.
- To develop a system operating cost model for renewable generation resources and energy storage.
• To develop an AC optimal power flow model that properly represents a power system with high penetrations of renewable generation and energy storage.

• To design a methodology to study the effect of renewable generators and energy storage on GHG emissions in an electric power system.

• To investigate how renewable generation affects system operating costs and reliability.

• To investigate how energy storage affects system operating cost and reliability.

Based on the fact that CO₂ is a primary GHG and represents the largest amount of GHG emissions, this dissertation focuses solely on CO₂ emissions. Other GHGs and air pollutants are not included in the analysis, although they are emitted from electric generators.

1.3 Organization of Dissertation

Chapter 1 provides background on GHG emissions and renewable generation resources. This chapter also presents objectives, scope of work, and organization of the dissertation. Chapter 2 investigates electricity markets for wind and solar in the U.S. Renewable policies and related research are also reviewed in this chapter. Chapter 3 investigates the integration of renewable generation and related factors. Chapter 4 develops system operating cost models for renewable generation and energy storage. The methodology to study renewable generation resources and energy storage is presented in Chapter 4. Study cases are created and simulation results, including discussions, are provided in Chapter 5. Conclusion and future work is presented in Chapter 6.
CHAPTER 2
LITERATURE REVIEW

This chapter reviews electricity markets, standards and policies, and corresponding research for renewable resources. Section 2.1 investigates various electricity markets for renewable generation in different control areas in the U.S. It shows how Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) operate their electricity markets for variable generators. Scheduling, ancillary services, and imbalance settlements are also discussed in this section. Section 2.2 reviews standards and policies on renewable generation in the U.S. This section mainly focuses on state renewable portfolio standards. Section 2.3 reviews previous research regarding renewable generators, energy storage, and studies of GHG emissions in electric power systems.

2.1 Renewable Generation and Electricity Market

The variable characteristic of renewable resources causes special operating issues and requires specific market procedures. The electricity markets for renewable resources have been designed, developed, and changed in recent years. This section investigates current electricity markets for wind and solar energy.

2.1.1 Wind Market

A large amount of wind penetration has dramatically affected electricity markets in the U.S. Many ISOs and RTOs have developed new market rules or special programs especially for wind energy. A state-of-the-art centralized forecasting system is implemented in order to effectively operate this variable generation. The following are reviews of wind electricity markets of each ISO/RTO in the U.S.
2.1.1.1 California Independent System Operator

In the California Independent System Operator (CAISO) market, a wind generator can be considered as a qualifying facility (QF), which is considered a “must-take” resource. CAISO is required to accept all energy produced and pay the avoided cost of energy production to wind producers [5]. The avoided cost includes capacity cost, which is the cost of new generation units that are avoided because of QFs and energy cost. This concept tends to generate high revenue for wind energy providers at first. However, the avoided cost can be diminished if utilities do not require new generating facilities. This results in less revenue for wind power resources.

In 2004, CAISO implemented the Participating Intermittent Resource Program (PIRP) in which renewable resources can be scheduled and bid in the CAISO forward market. Instead of being charged for ten-minute deviations and hourly deviations from their bid amounts of energy, the participants are charged based on net monthly deviation, which is insignificant when utilizing unbiased wind forecasting.

CAISO has integrated a wind forecasting system to support its market. PIRP participants are required to provide telemetry required by the forecasting system. Wind generators who participate in PIRP share a cost of the centralized wind forecasting system by paying a forecasting fee of $0.10 per megawatt-hour ($/MWh) [5].

Wind generators currently do not participate in the market for ancillary services. A recent CAISO report [6], however, stated that the requirement of system frequency regulation will significantly increase due to the installation of new wind power plants.

2.1.1.2 New York Independent System Operator

For wind generators and other renewable resources, the New York Independent System Operator (NYISO) has special market rules that exempt these variable generators from
imbalance charges. In 2008, NYISO increased the capacity of renewable resources that are eligible for these special market rules from 1,000 MW to 3,300 MW [7] due to the increasing capacity of renewable resources in the state of New York. A large number of wind power plants have been integrated into the NYISO’s electric power grid in recent years. Wind generation will reach a capacity of 1,200 MW in summer 2009 and may exceed 3,300 MW in the next couple of years, according to NYISO’s study [8].

A wind dispatch proposal is currently being prepared by NYISO. Dispatching of wind power plants is expected to be implemented in 2009 [8]. In the proposal, wind power producers will submit energy bids that indicate the locational based marginal price (LBMP) they would like to receive, to the ISO real-time market. The NYISO will send dispatch signals to wind power plants. The re-dispatch signal may be sent to curtail the output of wind plants when needed for system reliability and operating issues. Wind power plants will still be paid for over-generation and will still be exempted from charges for under-generation with regards to economic dispatch.

In June 2008, NYISO initiated a centralized wind forecasting system in order to forecast wind output, which will be used in the day-ahead and real-time markets [8]. Wind data, including speed, direction, and location, are sent from wind power plants to the ISO. Forecasts will be incorporated into NYISO’s day-ahead and real-time security-constrained economic dispatch.

Traditionally, wind energy does not participate in the ancillary service market in NYISO. However, the increasing amount of variable resources, which require additional reserves and regulations, have brought NYISO to investigate the new sources and market rules for ancillary services for wind energy.
2.1.1.3 PJM Interconnection

With peak load capacity at 144,644 MW [9], PJM Interconnection (PJM) operates one of the largest electric power systems in North America. As of 2008, PJM operates 1,147 MW of wind power plants [10].

For the PJM day-ahead market, wind power plants schedule their outputs for the next operating day, and the schedule is assigned as financially binding [10]. For the real-time market, wind power plants will be paid for the energy provided at the locational marginal price (LMP). PJM currently uses a balancing market operating reserve charge for imbalance settlement. Basically, all generating resources will be charged for deviations from their scheduled production. For the day-ahead market, deviations of more than 5 percent of the day-ahead schedule, or 5 MW, will be charged [11]. PJM proposes the modification of the balancing market operating reserve charge by separating MW deviation into two parts: the deviation associated with fuel (wind) predictability and the deviation due to turbine performance issues that are not reported to PJM. Wind generators will be exempt from the MW deviation associated with fuel predictability. The second part, however, will apply to wind power plants.

Since there is no requirement for additional reserves or regulation for wind power plants in the PJM market, the currently installed wind resources do not participate in ancillary service markets.

PJM is currently integrating a wind forecasting system in order to support its day-ahead and real-time markets. The forecast MW capacity will be used in the day-ahead market as price taker [11]. A price taker is referred to an investor whose transactions do not affect the price. Wind power plants submit required data for the PJM forecasting system. If the data comply with all requirements of PJM, wind will be exempted from the balancing market operating reserve
charge. On the other hand, wind plants will be charged with operating reserve deviations if the data provided do not comply with the requirement.

2.1.1.4 ISO New England

ISO New England (ISO-NE) operates New England’s electric power system. A typical peak load in the summer is up to 23,000 MW [12]. Wind generation, which accounts for approximately 5 MW capacity in service [13], is a relatively small amount compared to the New England system peak demand.

Wind can participate in day-ahead and real-time markets. For the day-ahead market, wind plants can either submit offers to the day-ahead market or self schedule their real power output for each hour in the next day [14]. The real-time MW output is settled with the real-time nodal price. There is no deviation charge for wind generation. However, wind power plants will need to inform ISO-NE if the real-time power output is different from its self-schedules.

There is an operating reserve market for wind [14]. ISO-NE is now investigating products that help mitigate the variability of wind and other renewable resources. There was no centralized wind forecasting system as of 2007. But a forecasting system may be developed in the future depending on the amount of additional wind capacity.

2.1.1.5 Electric Reliability Council of Texas

Texas is leading the nation in its installed wind power capacity. Wind resources in the amount of 6,023 MW are installed, and an additional 53,435 MW of wind are currently under review [15]. In 2008, wind power accounts for 7.1 percent of installed generating capacity in the control area of the Electric Reliability Council of Texas (ERCOT) [16]. Major wind resources are located in the western part of the state.
Transactions for the wind resource are done based on a bilateral market, while LBMP is expected to be utilized in 2009 [14]. Like other generators, wind power plants will schedule their output as a qualified schedule entity (QSE). The high sustained limit (HSL), which is the resource’s maximum sustained energy production capability, identifies generating capability. In the day-ahead market, the HSL of the wind power plant cannot be higher than forecast wind output [17].

In real-time operation, ERCOT dispatches the power output of wind as a base point. Wind plants need to take action when signaled to be curtailed by ERCOT. Wind power plants have a wide acceptable range above the base point, or 10 percent, while the acceptable range for conventional generators is 5 percent [17]. There is no imbalance charge for wind output lower than the base point. With consideration of the base point and HSL, the deviation charge may be applied when the output exceeds the acceptable range.

At ERCOT, ancillary services have been procured and assigned through loads. Wind power resources do not need to provide ancillary services. ERCOT is currently studying the ancillary service needed for increasing amounts of wind power resources. ERCOT provides short-term forecasts for wind resources based on necessary wind data. Wind power resources must submit the data, which include wind plant specifications, operational data, and availability.

2.1.1.6 Midwest ISO

Although its name includes ISO, Midwest ISO (MISO) is not an independent system operator. MISO is a Regional Transmission Organization (RTO) that supports the system reliability of electric power grids in fifteen U.S. states and the Canadian province of Manitoba. MISO, approved by FERC as a RTO in 2001, is the first RTO in the U.S. MISO monitors thirty five control areas in its territory.
For the day-ahead market, wind resources can either offer a bid or not participate in the market. However, if a wind plant participates as “capacity resource,” a wind plant is obligated to offer energy in the day-ahead market [14]. Imbalance charges will be applied when wind resources participate in the day-ahead market. In the real-time market, wind will be a price taker and is exempt from any deviation charge. There is currently no centralized wind forecasting system, but MISO is considering the possibility of one. MISO uses a 15 percent capacity credit for wind power plants for planning.

2.1.1.7 Southwest Power Pool

Approved by FERC as an RTO in 2004, the Southwest Power Pool (SPP) supervises system reliability of electric power grids in nine U.S. states. SPP has large wind resources, especially in Kansas, Oklahoma, New Mexico, and some parts of Texas. Approximately, 1,800 MW of wind resources are currently in service, and more than 50,000 MW of wind projects are currently under review [18].

The transactions for wind energy have been done under a bilateral basis. The nodal pricing market is planned to be implemented in the SPP market in the future. Prior to 2007, there was no centralized energy market. The central energy market was integrated by SPP in 2007. Wind resources are now scheduled by using the forecast output in the centralized energy market. Ancillary services and cost allocation are being investigated.

2.1.2 Solar Market

Solar energy is basically treated the same way that electricity markets treat wind energy. The production of solar energy is more predictable than wind generator output. A solar plant generates electricity during the daytime when the sunlight shines on the solar plant. It always
gives zero output during the night. Unlike wind generation, the peak output period of solar power plant occurs during daytime when load is increasing and on peak.

2.1.2.1 California Independent System Operator

California has high potential for solar energy, especially in the southern desert portion of the state. Similar to wind energy, solar energy is a QF in the CAISO market. Solar energy providers also can participate in PIRP, which allows solar energy to bid in the forward market without being subject to ten-minute deviation charges.

The required meteorological and production data must be provided to the ISO’s centralized forecasting system. Important factors that affect the performance of solar energy include global solar irradiance, temperature, and wind [19].

2.1.2.2 New York Independent System Operator

Similar to wind and other variable resources, special market rules are applied to solar generation in the NYISO’s market. A solar energy provider will be paid for all energy produced without consideration of its day-ahead schedule. There is no deviation charge for under-generation when a solar plant generates output lower than its base point.

2.1.2.3 PJM Interconnection

When assigned as a capacity resource, a solar power plant must offer its energy in the day-ahead market according to the forecast value, and the cost schedule is considered zero [20]. The required telemetry and data must be sent by a solar power plant to PJM.

2.1.2.4 ISO New England

Solar generation assigned as a variable resource can offer energy in the day-ahead energy market. In the capacity market, there is no availability charge for variable resources. On the other
hand, solar plants will get paid for their qualified capacity. The qualified capacity of solar plants will be determined according to the ISO-NE’s calculating methodology.

2.1.2.5 Electric Reliability Council of Texas

In addition to high wind power resources, Texas also has excellent solar resource potential. In 2008, ERCOT had more than 800 MW of solar generation in its queue for studying and system planning. More solar energy providers are interested in participating in the ERCOT market.

While the forecasting system for wind-powered generation resources, which forecasts wind output to be used in the day-ahead market, reliability unit commitment, and hourly unit commitment has already been developed and implemented in the ERCOT market, a similar forecasting system for solar is being developed for increasing solar energy production.

2.1.2.6 Midwest ISO

Solar energy in the MISO market is likely to be procured and traded similar to wind energy. Currently there is no special rule or program designed exclusively for solar power plants.

2.1.2.7 Southwest Power Pool

In SPP’s control areas, solar is likely to be treated the same way that the market treats wind. There is presently no special procedure or rule specifically for solar power resources.

2.2 Renewable Standards and Policies

In order to reduce GHG released by the electric power industry, several states in the U.S. have created policies and standards that are enforced among concerned parties in the industry. A key issue is to increase the use of renewable generation resources to replace fossil-fired conventional generators, which drastically emit GHG into the atmosphere.
2.2.1 Renewable Portfolio Standard

A renewable portfolio standard (RPS) is a state policy that requires the state’s electric energy providers, including utilities and retailers, to achieve a minimum percentage of their generation from renewable generation resources. Varying from state to state, RPSs specify a minimum percentage of renewable generation and a target date. Currently twenty seven states and the District of Columbia implement RPSs [21].

California has created one of the most aggressive RPSs in the U.S. The California RPS mandates the state to achieve 20 percent of its procured electricity from renewable resources by 2010 [22]. The state also would like to obtain 33 percent of its electricity from renewable energy by 2020. In 2007, 12.7 percent of electricity generated by the three major investor-owned utilities– Pacific Gas and Electric, Southern California Edison and San Diego Gas and Electric– is procured from renewable energy resources.

In 2004, the state of New York implemented an RPS to increase renewable energy production in its electricity market. At that time, 19.3 percent of New York electric energy was generated by renewable resources. The New York RPS states that 25 percent of its electricity will be produced from eligible renewable energy resources by 2013. While 24 percent is mandatory, the remaining one percent is a voluntary market that New York people, businesses, and public agencies can support.

Leading the nation in wind power energy production, the state of Texas adopted the first RPS in 1999. The Texas RPS mandates all energy providers to provide additional capacity of 5,880 MW from renewable energy by 2015, and 10,000 MW by 2025. Because of its abundant wind energy resources, Texas has high potential to achieve RPS goals, and its RPS is considered to be a very successful renewable policy based on the current progress.
Table 2.1 summarizes each state’s RPS goals, including the required capacity of the electricity markets that must be supplied from renewable energy resources and the target date for the standard.

<table>
<thead>
<tr>
<th>State</th>
<th>Amount</th>
<th>Target Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arizona</td>
<td>15%</td>
<td>2025</td>
</tr>
<tr>
<td>California</td>
<td>20%</td>
<td>2010</td>
</tr>
<tr>
<td>Colorado</td>
<td>20%</td>
<td>2020</td>
</tr>
<tr>
<td>Connecticut</td>
<td>23%</td>
<td>2020</td>
</tr>
<tr>
<td>District of Columbia</td>
<td>11%</td>
<td>2022</td>
</tr>
<tr>
<td>Delaware</td>
<td>20%</td>
<td>2019</td>
</tr>
<tr>
<td>Hawaii</td>
<td>20%</td>
<td>2020</td>
</tr>
<tr>
<td>Iowa</td>
<td>105 MW</td>
<td>NA</td>
</tr>
<tr>
<td>Illinois</td>
<td>25%</td>
<td>2025</td>
</tr>
<tr>
<td>Massachusetts</td>
<td>4%</td>
<td>2009</td>
</tr>
<tr>
<td>Maryland</td>
<td>9.5%</td>
<td>2022</td>
</tr>
<tr>
<td>Maine</td>
<td>10%</td>
<td>2017</td>
</tr>
<tr>
<td>Minnesota</td>
<td>25%</td>
<td>2025</td>
</tr>
<tr>
<td>Missouri</td>
<td>11%</td>
<td>2020</td>
</tr>
<tr>
<td>Montana</td>
<td>15%</td>
<td>2015</td>
</tr>
<tr>
<td>New Hampshire</td>
<td>16%</td>
<td>2025</td>
</tr>
<tr>
<td>New Jersey</td>
<td>22.5%</td>
<td>2021</td>
</tr>
<tr>
<td>New Mexico</td>
<td>20%</td>
<td>2020</td>
</tr>
<tr>
<td>Nevada</td>
<td>20%</td>
<td>2015</td>
</tr>
<tr>
<td>New York</td>
<td>24%</td>
<td>2013</td>
</tr>
<tr>
<td>State</td>
<td>Amount</td>
<td>Target Year</td>
</tr>
<tr>
<td>------------------</td>
<td>---------</td>
<td>-------------</td>
</tr>
<tr>
<td>North Carolina</td>
<td>12.5%</td>
<td>2021</td>
</tr>
<tr>
<td>Oregon</td>
<td>25%</td>
<td>2025</td>
</tr>
<tr>
<td>Pennsylvania</td>
<td>18%</td>
<td>2020</td>
</tr>
<tr>
<td>Rhode Island</td>
<td>15%</td>
<td>2020</td>
</tr>
<tr>
<td>Texas</td>
<td>5,880 MW</td>
<td>2015</td>
</tr>
<tr>
<td>Utah</td>
<td>20%</td>
<td>2025</td>
</tr>
<tr>
<td>Vermont</td>
<td>10%</td>
<td>2013</td>
</tr>
<tr>
<td>Virginia</td>
<td>12%</td>
<td>2022</td>
</tr>
<tr>
<td>Washington</td>
<td>15%</td>
<td>2020</td>
</tr>
<tr>
<td>Wisconsin</td>
<td>10%</td>
<td>2015</td>
</tr>
</tbody>
</table>

2.3 Studies on Electric Power Systems and GHG Emissions

Previous research [23-36] has investigated and studied the relation of electric power systems and GHG emissions. M. Shao [23] investigated power system features that impact CO₂ emissions, and developed a CO₂ emission-incorporated AC optimal power flow (OPF). He developed the objective function of the optimal power flow by incorporating CO₂ emission costs together with fuel costs in the objective function. Finally, CO₂ emissions are calculated based on dispatched MW from the OPF. The new objective function [23] of this CO₂ emission-incorporated AC OPF can be shown as

\[
\min \left\{ \sum_{i=1}^{N_{g}} F_{\text{total,ij}}(P_i) \right\} = \min \left\{ \sum_{i=1}^{N_{g}} \left[ F_{\text{fuel,ij}}(P_i) + F_{\text{CO₂,ij}}(P_i) \right] \right\}
\]

\[
= \min \left\{ \sum_{i=1}^{N_{g}} \left[ (C_j + C_{\text{CO₂}} + \epsilon f_j) (k_{r0} + k_{r1}P_i + k_{r2}P_i^2) \right] \right\}
\]

where the \( F_{\text{total,ij}}(P_i) \) is the fuel-emission cost function, \( N_{g} \) is the number of generators in the
system, \( F_{\text{fuel}_{ij}}(P_i) \) is the fuel cost of generator \( i \) using fuel \( j \) in $/h, \( F_{\text{CO2}_{ij}}(P_i) \) is the CO\(2\) emission cost of generator \( i \) using fuel \( j \) in $/h, \( C_j \) is the given price of fuel \( j \) in $/MBtu, \( C_{\text{CO2}} \) is the given CO\(2\) price in $/ton, \( e_{f_j} \) is the CO\(2\) emission factor of fuel \( j \), \( P_i \) is the real-power output of generator \( i \), and \( k_{i0}, k_{i1}, \) and \( k_{i2} \) are polynomial heat rate coefficients. The polynomial coefficients are derived from curve fitting the heat rate data.

A number of researchers [24, 25, 26, and 27] have investigated the integration of wind generation in an electric power system. Denny et al., [24] presented a dispatch model to study the impact of wind generation on the Irish electric power system. The GHG emissions including CO\(2\) emissions were also studied in this research. Gil et al., [25] developed a generalized methodology that utilizes several wind profiles and dispatch strategies in order to achieve emissions standard goals. Cardogan et al., [26] concluded that integrating a modest amount of wind generation into the U.S. electric power grid should not cause any problems due to wind fluctuation, but the effects are still unclear for large wind penetrations. Hezer et al., [27] presented an economic dispatch model that incorporates wind power resources. The characteristics of wind are represented by a Weibull probability density function. The penalty cost and reserve requirement cost are included in the analysis. Ahlstrom et al., [28] discussed an idea to integrate a wind forecasting system into the energy management system (EMS) in which the wind forecasting system is implemented in a dispatch training simulator (DTS).

Some researchers [29, 30, 31 and 32] focus mainly on costs of wind generation. Smith et al., [29] studied the impacts of wind power on system operating cost. This research concludes that the system operating cost for wind is relatively low with low amounts of wind integration, and the cost increases as the amount of wind integration increases. The research shows that cost in the unit commitment time frame is the most significant cost. The system operating costs
impacted by wind integration during 2003–06 are shown by [30]. These costs, which include regulation cost, load following cost, unit commitment cost and gas supply cost, vary from $1.85/MWh to $4.97/MWh. In 1996, Wiser et al., [31] investigated the capital costs of wind generation based on ownership and financial structures. Based on their study, the cost varies from 2.88 cents per kilowatts-hour (cents/KWh) to 4.95 cents/KWh. Yeh et al., [32] derived a cost function for wind generation. This research calculated the cost of electricity generated by wind power. The cost of electricity includes capital cost, operation and maintenance cost.

Many researchers [33, 34] utilize time series to represent characteristics of variable resources since the power outputs of renewable generation vary based on time. Boehme et al., [33] used time series and power flow analysis to study a large penetration of wind in the Scottish electric power system. Historical data of load and wind generation were used in this analysis. However, the historical or real data are normally difficult to obtain. Decker [34] presented his methodology to generate synthetic data for wind generation in order to investigate the electricity market in Belgium. His research includes calculation of a transition probability matrix in order to generate time series.

Widely known for its benefits and applications, energy storage is considered a solution to many issues and drawbacks in electric power systems. Jewell et al., [35] concluded that distributed energy storage may be utilized in higher penetration than distributed generation in the future. A recent paper [36] presents a technique to convert annual cost of energy storage into the cost added to store electricity and return it to the electricity grid. The technique considers two costs of energy storage: power cost and energy cost. The cost added to store each unit of electricity can be calculated as [36]

\[
COE = \frac{(AC + OMC + ARC)}{PnH_oD}
\]  

(2.3)
where COE is the cost added to a unit of electricity stored, AC is the annualized capital cost in $/year, OMC is the total annual fixed operation and maintenance cost in $/year, ARC is the total annual replacement cost in $/year, P is the rated power output capacity of energy storage in kW, n is number of charge/discharge cycles per day, \( H_o \) is the length of each discharge cycle in hours, and D is annual operating days.

The annualize capital cost (AC), which includes power cost, energy cost, and balance of plant cost, is [36]

\[
AC = (PCS + SUC + BOP) \frac{(i_r(1+i_r)^y)}{((1+i_r)^y - 1)}
\]

where PCS is the cost for the power conversion system in dollars, SUC is the cost for storage units in dollars, BOP is the cost for balance of plant, \( i_r \) is the annual interest rate, and \( y \) is the lifetime of energy storage.

The annual replacement cost for battery energy storage can be shown as

\[
ARC = \frac{(PH_oSUC[(1+i_r)^{-y} + (1+i_r)^{-2y} + ...])}{eff} \frac{(i_r(1+i_r)^y)}{((1+i_r)^y - 1)}
\]

where \( eff \) is the efficiency of energy storage. The number of terms in the factor of equation (2.5) is equal to the number of times batteries need to be replaced during the system’s life.
CHAPTER 3
INTEGRATION OF RENEWABLE GENERATION

The integration of renewable generation may affect an existing power system in terms of system operating cost, emissions, and system reliability. Several factors need to be considered when renewable generation is integrated into an electric power system. These factors include location of renewable generation, number of required reserve units, transmission congestion, and system security. This chapter provides the basic background and analyzes these factors by using a simple three-bus, three-generator system as an example. Section 3.1 presents the simple three-bus, three-generator power system, which is used to discuss these factors. Sections 3.2 to 3.5 analyze each factor and its effects, especially on system operating cost and total CO$_2$ emissions. Section 3.6 provides overall discussion of this chapter.

3.1 Three-bus, Three-generator Power System

This dissertation utilizes a simple three-bus, three-generator power system to analyze the factors that affect an electric power system due to integration of renewable generation. The system consists of three fossil-fired generators installed at different buses.

Figure 3.1 presents a three-bus, three-generator power system with a load at bus 3. The generator at bus 1 is a 100 MW gas-fired generating unit G1. The generator at bus 2 is a 150 MW coal-fired generating unit G2. At bus 3, a 100 MW gas-fired generator and 200 MW load are connected. TL12 is a transmission line from bus 1 to bus 2. TL13 is a transmission line from bus 1 to bus 3, and TL23 is a transmission line from bus 2 to bus 3. Line limits during normal operation for each transmission line are 100 MVA. In this analysis, the fuel cost is assumed to be $2.06/MBtu for coal and $9.34/MBtu for gas.
Figure 3.1. Three-bus, three-generator power system.

By using linear programming to optimally dispatch all generators (determine the combination of generator outputs that serve the load at lowest cost), the system dispatches 150 MW from coal-fired generator G2 and 50 MW from gas-fired generator G3 to serve the 200 MW load at bus 3. Figure 3.2 shows the system with optimal economic dispatch. A total of 100 MW from G2 flows through the transmission line TL23, while G2’s 50 MW travels through TL12 and TL13 to serve the load at bus 3.

Figure 3.2. Three-bus, three-generator power system with OPF.
3.2 Location of Integrated Renewable Generation

Location of newly installed renewable generation is an important factor that affects system operation and dispatch. Different locations of renewable generation installed provide differences in system dispatch and operating cost as well as emissions. To analyze this issue, a 100 MW wind power plant is integrated into the three-bus, three-generator power system. In this case, a wind power plant is added at bus 1. Figure 3.3 presents the resulting three-bus, four-generator system. Based on available wind resources, the wind generator produces 20 MW output, and this generation is considered as must-take energy. According to the optimal power flow analysis, the remaining 180 MW supply comes from G2 (140 MW) and G3 (40 MW). Although generation from G2 is lower cost than G3, if G2 is increased beyond 140 MW, line TL23 will be overloaded beyond its 100 MVA limit. The 40 MW from G2 flows on TL12 and TL13 to meet the load at bus 3, while the other 100 MW of G2 flows on TL23 to serve the load at bus 3. TL13 moves a total of 60 MW of electricity from wind (20 MW) and G2 (40 MW). The wind generator located at bus 1, with 20 MW output, thus reduces the coal-fired generator at bus 2 and the gas-fired generator at bus 3 by 10 MW each.

Figure 3.3. Three-bus, four-generator power system with a wind generator at bus 1.
In the second case, a wind power plant is installed at bus 2. It also generates 20 MW into the system. Figure 3.4 illustrates the three-bus, four-generator system with a wind generator installed at bus 2. Based on economic dispatch, G2 generates 130 MW and G3 produces 50 MW to supply 200 MW load. G1 is still running but generates no active power at zero MW. Moving the wind generator to bus 2 reduces the output of the coal plant at bus 2 by another 10 MW and increases the output of the gas plant at bus 3 by the same 10 MW.

![Diagram of a three-bus, four-generator power system with a wind generator at bus 2.](image)

Figure 3.4. Three-bus, four-generator power system with a wind generator at bus 2.

Figure 3.5 presents CO$_2$ emissions from the three-bus, four-generator system. This dissertation assumes a CO$_2$ emissions factor of 215 lb/MBtu for coal and 117 lb/MBtu for gas. There are no CO$_2$ emissions from a wind plant. With a wind generator installed at bus 1, hourly CO$_2$ emissions are 865 tons. In this case, G2 emits 524 tons of CO$_2$ per hour, which is 215 lb/MBtu multiplied by the coal input [23], while G3 emits 179 tons of CO$_2$ per hour.

With wind installed at bus 2, total CO$_2$ emissions changes to 861 tons each hour, lower than before because coal plant output is further reduced. G2 emits 516 tons of CO$_2$ each hour, and G3 emits 183 tons of CO$_2$ per hour. G1 emits 162 tons of CO$_2$ per hour in both cases,
although it is operating at zero MW. The connecting point of renewable generation affects the economic dispatch of generators and results in a change in CO\(_2\) emissions.

![Figure 3.5. Hourly CO\(_2\) emissions with different locations of renewable generation.](attachment:image.png)

The location of newly installed renewable generation also affects the system operating cost. Figure 3.6 shows the system operating cost for each case. Without consideration of the operating cost of the wind plant, the operating cost of the system with wind installed at bus 1 is $8,198 per hour, while the system operating cost of the system with wind installed at bus 2 is $8,812 per hour. The cost is higher in the second case because coal output is reduced and gas output is higher than in the first case. Different connecting points of a wind generator cause change in system dispatch and, therefore, change in operating cost.
3.3 Reserve Units

A fossil-fired generation unit is usually assigned as a spinning reserve unit, which operates to support renewable generation whose output is unknown at any time. The number of spinning reserve units on the system therefore affects system operations. With a wind generator connected to the system at bus 1 and generating 20 MW output, as shown in Figure 3.3, a gas-fired generator G1 may be assigned as a spinning reserve unit running at zero MW to provide generation to the system when wind output drops. Figure 3.7 shows hourly CO₂ emissions from generators in two different cases: G1 is committed as a spinning reserve, and G1 is off-line (no reserve units). With G1 committed as a spinning reserve running at zero output, the system emits 865 tons of CO₂ per hour. Without reserve units, the hourly CO₂ emissions are reduced to 703 tons, but the system would not be reliable in this case, and it would not be allowed by ISO/RTO rules. According to Figure 3.7, G1 emits 162 tons of CO₂ per hour when it operates at zero MW acting like a reserve unit. G1, however, emits no CO₂ when it is off-line. Other generators emit same amount of CO₂ in both cases.
Figure 3.7. Hourly CO\textsubscript{2} emissions with and without G1 as a reserve unit.

System operating cost is also affected by the requirement of reserve units. Figure 3.8 shows the operating cost of the three-bus, four-generator system. Without any reserve unit, the system operating cost is $6,987 per hour. The cost increases to $8,198 per hour when G1 is committed to run as a spinning reserve, which is necessary for system reliability.

Figure 3.8. System operating cost with and without G1 as a reserve unit.
3.4 Transmission Congestion

Figure 3.9 presents the three-bus, four-generator power system with a wind generator connected at bus 2. In this example, the wind generator operates at its full rated capacity (100 MW). At bus 2, a total of 150 MW is produced by G2 (50 MW) and the wind plant (100 MW). Fifty megawatts of generation from bus 2 flows through TL12 and TL13 to serve the load at bus 3. TL23 moves 100 MW of electric power at its full rated capacity, and transmission congestion occurs. G3 generates 50 MW at bus 3 to serve the remaining demand because of the congestion on line TL23.

Figure 3.9. Three-bus, four-generator power system with a wind generator at bus 2.

Figure 3.10 presents the three-bus, four-generator power system in which the MVA limit of TL23 increases to 200 MVA. According to economic dispatch for the new system condition, G2 and the wind generator each generate 100 MW. G3, however, the higher-cost generator, is again running at zero MW. TL23 now moves 133 MW of electricity from bus 2 to bus 3. The remaining electricity flows through TL12 and TL13 to serve the load.
Figure 3.10. Three-bus, four-generator power system with 200 MVA line limit for TL23.

The hourly CO$_2$ emissions from the three-bus, four-generator power system for both cases are presented in Figure 3.11. The system with 100 MVA limit on all transmission lines emits 797 tons of CO$_2$ each hour. The system with 200 MVA limit of TL23 aiming to relieve congestion, however, emits 815 tons of CO$_2$ per hour. The increase in overall CO$_2$ emissions is caused by committing more generation from coal-fired G2, which has a higher emission rate than the other generators.

Figure 3.11. Hourly CO$_2$ emissions with different MVA transmission limits.
The system operating costs with different MVA transmission limits are shown in Figure 3.12. The operating cost of the system with all transmission line limits of 100 MW is $7,396 per hour. For the system with increased 200 MVA line limit of TL23, the system operating cost is $4,473 per hour. In this case, the congestion of TL23 is relieved, and more economical electricity can be transferred from G2 to serve the load.

![System Operating Cost Chart](image)

Figure 3.12. System operating cost with different MVA transmission limits.

### 3.5 System Security

In addition to normal operation conditions, a system dispatcher may consider contingency conditions to ensure that a power system can withstand the loss of any single transmission line or major component with the remaining equipment still operating within the normal range of their operating limits. Figure 3.4 presents the economic dispatch of the three-bus, four-generator system including a wind generator at bus 2. If the transmission line TL12 is forced to open for some reason (e.g., short circuit or fire), 150 MW of power will flow on TL23.
The line limit of TL23, however, is only 100 MVA. As a result, TL23 is overloaded. Figure 3.13 presents the system condition dispatched by normal dispatch, which does not consider congestion, during loss of TL12.

![System Condition Diagram]

Figure 3.13. Normal dispatch during loss of TL12.

To prevent such an overloading condition to happen, contingencies must be included into the system constraints. The system is re-dispatched during the loss of each of the three transmission lines: TL12, TL13, and TL23. With the new system OPF dispatch, the system is able to withstand the loss of any single transmission line, and the remaining lines will not be overloaded. In this case, G2 is redispatched to generate 80 MW, and G3 generates 100 MW, while the wind generator produces 20 MW. Figure 3.14 illustrates the system condition dispatched by security-constrained OPF during loss of TL12. TL23 now carries a total of 100 MW from G2 and the wind generator to bus 3. The other 100 MW of load power comes from G3 at the bus 3. Although the system loses TL12, it is still able to operate without overloads on the remaining transmission lines.
Figure 3.14. Security-constrained OPF during loss of TL12.

Figure 3.15 shows the hourly CO$_2$ emissions of the three-bus, four-generator system operating without TL12. According to the figure, the system dispatched by normal economic dispatch emits 861 tons of CO$_2$ per hour, but TL23 is overloaded. Considering contingencies, the system dispatched with security-constrained OPF emits 844 tons of CO$_2$ each hour.

Figure 3.15. Hourly CO$_2$ emissions of three-bus, four-generator system without TL12.
Figure 3.16 shows system operating costs of the three-bus, four-generator power system operating without TL12. When the system is dispatched by normal economic dispatch, the hourly operating cost is $8,812 per hour. When the system is dispatched with consideration of loss of each transmission line, the operating cost rises to $12,248 per hour.

![Figure 3.16. System operating cost of three-bus, four-generator system without TL12.](image)

### 3.6 Discussion

Several factors must be considered when renewable generation is connected to an existing system. These factors include location of renewable generation, required reserve units, transmission congestion, and system security. The effects on the power system are operating cost, total emissions, and system reliability. Tradeoffs among operating cost, system reliability, and environmental issues need to be carefully analyzed, especially in more complicated power systems.
CHAPTER 4
MODELING AND METHODOLOGY

This chapter investigates the operating costs of fossil-fired generators and develops operating cost models for renewable generation and energy storage. A total system operating cost of a power system is formulated based on these cost models. The objective function and system constraints are developed for an AC optimal power flow for the electrical power system with large integration of renewable generation and energy storage. These are also applied to security-constrained optimal power flow (SCOPF) in which contingencies are also considered. Finally, the methodology to fully implement renewable resources and energy storage into AC optimal power flow and SCOPF is presented and discussed.

4.1 System Operating Cost

Operating cost does not include the capital cost for any generating or storage unit. Operating cost is only the cost to operate units that are already installed. If the costs to build new units are to be considered in an analysis, they must be calculated separately and added to the analysis. In this dissertation, only operating costs are considered.

4.1.1 Fossil-fired Generating Unit

The operating cost of a fossil-fired generating unit under a CO₂ market or tax includes fuel cost and CO₂ emission cost. Both costs are based on unit characteristics, which are the relations between gross heat rate input and net electric power output of the unit. Fuel cost, which includes operation and maintenance costs [37], can be obtained from the product of heat rate input to the unit and a given fuel price. In a similar manner, CO₂ emission cost can be calculated based on the amount of CO₂ emitted from a generating unit, which is proportional to the type and amount of fuel input. The operating cost of a fossil-fired generating unit is shown as
where $F(P_i)$ is the system operating cost function of fossil-fired generator $i$ using fuel $j$ in $$/h$, $C_j$ is the given price of fuel $j$ in $$/MBtu$, $C_{CO2}$ is the given $CO_2$ price in $$/ton$, $ef_j$ is the $CO_2$ emission factor of fuel $j$ in lb/MBtu, $P_{fi}$ is the real power output of fossil-fired generator $i$, and $k_{i0}$, $k_{i1}$, and $k_{i2}$ are polynomial heat rate coefficients. This cost model can also be applied to a nuclear generating unit.

### 4.1.2 Renewable Generation

Fuel for renewable generation such as wind and solar is available in nature and free to obtain. Thus, there is no fuel cost for these variable generators. The emission cost can be disregarded since renewable resources generate no carbon during operation. The independent system operator pays renewable generators for the real-time marginal or incremental price, the cost the system avoids spending to operate other generation, for any energy the renewable generators produce. On the other hand, renewable generation providers pay a forecasting fee and deviation fee back to the independent system operator to share the centralized forecasting system and other operating costs. The operating cost for renewable generation can be written as

$$F(P_{ri}) = P_{ri}(\lambda_n - C_f - C_d)$$

where $F(P_{ri})$ is the cost function of renewable generator $i$ in dollars per hour ($$/h$), $P_{ri}$ is the real power output of renewable generator $i$, $\lambda_n$ is the locational marginal price at bus $n$ in $$/MWh$, $C_f$ is the system forecasting fee in $$/MWh$, and $C_d$ is net monthly deviation charge in $$/MWh$. The deviation charge is based on the monthly difference between scheduled generation and actual generation of renewable generators.

Locational marginal price is the nodal pricing system that considers system energy balance, transmission congestion and line losses. LMP can be expressed as
\[ \lambda_n = \lambda_N - \sum_k \mu_k S_{kn} - \lambda_N F_n \]  

(4.3)

where \( \lambda_N \) is the shadow price of the system energy balance constraint in $/MWh, \( \mu_k \) is the shadow price of the transmission line constraint \( k \), \( S_{kn} \) is the incremental amount of power flow on transmission line \( k \) when an additional unit of power is injected into node \( n \) and withdrawn at a reference node, and \( F_n \) is the loss contribution factor at bus \( n \).

The LMP consists of three components: energy price, congestion price, and marginal loss price. The energy price is the shadow price of the system energy balance constraint and is the same for all buses in an electrical power system.

The congestion price indicates bus contribution to overall system congestion. When the bus congestion price in dollars per MWh is less than zero, increasing bus load will mitigate overall system congestion, while increasing bus generation will increase overall system congestion. On the other hand, when the bus congestion price is greater than zero, increasing bus load will increase overall system congestion, whereas increasing bus generation will help mitigate overall system congestion.

The marginal loss price represents the bus’s contribution to network transmission losses. When bus marginal loss price in dollars per MWh is less than zero, increasing bus load will reduce overall system losses, while increasing bus generation will increase overall system losses. On the other hand, when the bus marginal loss price is greater than zero, increasing bus load will increase system losses whereas, increasing bus generation will reduce system losses.

4.1.3 Energy Storage

The cost for operating an energy storage system involves operation and maintenance of the system. The annual operation and maintenance cost can be calculated from the product of fixed annual operation and maintenance cost in dollars per MW per year and rated power output
of the energy storage in MW. The operating cost of energy storage can be derived from the technique that converts the annual cost of an energy storage system into the cost added to each unit of energy stored and returned to the electric grid [36]. The system operating cost of energy storage is

\[ F(P_{si}) = P_{si} \frac{OM_f}{nH_o d} \]  

(4.4)

where \( F(P_{si}) \) is the cost function of energy storage i in dollar per hour ($/h), \( P_{si} \) is the real power output of energy storage i in MW, \( OM_f \) is the annualized fixed operation and maintenance cost in $/MW, \( n \) is number of charge/discharge cycles per day, \( H_o \) is the length of each discharge cycle in hour (h), and \( d \) is the annual operating days per year. Another term, representing the cost of periodically replacing batteries during the life of a battery storage system, could be added to this.

An alternate way of representing the operating cost of electric energy storage is to determine the difference in value between cost of electricity during charging and cost of electricity during discharging. When storage is used for peak reduction or cost savings, cheaper electricity is used to charge storage during the off-peak period. The system is paid for this energy at a rate equal to or a function of the LMP at the storage node. Energy storage later discharges electricity back to the grid during peak periods, for which the system pays a higher electricity price, which is again the LMP or a function of the LMP. The alternate system operating cost function can be expressed as

\[ F_a(P_{si}) = P_{si} (COE_{on_peak} - COE_{off_peak}) \]  

(4.5)

where \( F_a(P_{si}) \) is the alternate cost function of energy storage i in dollars per hour ($/h) based on the cost of electricity, \( COE_{on_peak} \) is the cost of electricity during the on peak period in dollars per MWh, \( COE_{off_peak} \) is the cost of electricity during the off peak period in dollars per MWh, and the
The last term is the O&M cost defined in equation (4.4). Equation (4.5) results in significantly higher costs to the system than equation (4.4), but savings to the system still result if storage discharge results in a decrease in COE_{on-peak} during discharge.

### 4.1.4 Total System Operating Cost

Total system operating cost of the electric power system is the sum of operating costs of fossil-fired generating units, renewable generators, and energy storage systems. The total system operating cost can be written as

\[
F_{\text{total}}(P_i) = \sum_i F(P_{fi}) + \sum_i F(P_{ni}) + \sum_i F(P_{si})
\]

\[
= \sum_i (C_j + C_{CO_2} + e f_j)(k_{i0} + k_{i1}P_{fi} + k_{i2}P_{fi}^2)
\]

\[
+ \sum_i P_{ri}(\lambda_{ri} - C_f - C_d) + \sum_i P_{ri} \frac{OM_f}{nh} D
\]

Equation (4.7) is the operating cost equation used for all simulations in this dissertation. The final term of equation (4.7) can be replaced with equation (4.5) to represent the alternative cost function of energy storage.

### 4.2 AC Optimal Power Flow

Optimal power flow dispatches generators or other devices by adjusting control variables in order to optimize the objective function while enforcing system constraints. This dissertation utilizes the full scale AC optimal power flow (AC OPF), which considers all variables.

#### 4.2.1 Objective Function

In the research, the objective function of the AC OPF is to minimize system operating cost by adjusting the output of all generators in the system. The cost function of fossil-fired generators can be applied from equation (4.1) which considers both fuel cost and emission cost. Since a renewable generator is currently considered a “must-take” source whose output the
system must purchase, it submits a bid of zero cost, and the cost function of renewable
generators is considered zero when it is input in the objective function of the OPF. Because
energy storage, similar to hydroelectric generation, is energy-limited and thus not always
available, its dispatch is determined outside AC OPF, and the cost function of energy storage is
also excluded from AC OPF dispatch calculations. The objective function of AC OPF is thus

\[ \min \left\{ \sum_{i=1}^{N_f} F_{\text{total}}(P_i) \right\} = \min \left\{ \sum_{i=1}^{N_r} \left[ (C_j + C_{CO_2} \times ef_j)(k_{i0} + k_{i1}P_{fi} + k_{i2}P_{fi}^2) \right] \right\}, \tag{4.8} \]

where \( N_f \) is the number of fossil-fired generators in the system.

Equation (4.8) excludes costs for renewables and storage because they are not dispatched
by the OPF. Equation (4.7), however, provides the overall system operating cost that includes
operating costs of renewable generators and energy storage. The renewable and storage costs
omitted from equation (4.8) will be calculated after the OPF solves for dispatch and is included
in the total system operating cost.

### 4.2.2 Equality and Inequality Constraints

The equality constraints include the system real power balance and the system reactive
power balance, which are shown in equations (4.9) and (4.10), respectively. During charging,
energy storage behaves similarly to system load, and the power is negative. In contrast, energy
storage injects power back to the grid during discharge, and the power is positive.

\[ \sum_{i=1}^{N_f} P_{fi} + \sum_{i=1}^{N_r} P_{ri} \pm \sum_{i=1}^{N_s} P_{si} = P_{\text{Load}} + P_{\text{Loss}} \tag{4.9} \]

\[ \sum_{i=1}^{N_f} Q_{fi} + \sum_{i=1}^{N_r} Q_{ri} \pm \sum_{i=1}^{N_s} Q_{si} = Q_{\text{Load}} + Q_{\text{Loss}} \tag{4.10} \]

where \( N_f \) is the number of renewable generators in the system, \( N_s \) is the number of energy
storage units in the system, \( P_{\text{Load}} \) is system total real power load, \( P_{\text{Loss}} \) is system total real power
loss, $Q_i$ is the reactive power output from fossil-fired generator $i$, $Q_{ri}$ is the reactive power output from renewable generator $i$, $Q_{si}$ is the reactive power output from energy storage $i$, $Q_{Load}$ is system total reactive power load, and $Q_{Loss}$ is system total reactive power loss.

The inequality constraints indicate system operating limits, which include the real power limit, reactive power limit, bus voltage limit, bus voltage phase angle limit, and transmission line loading limit. These constraints are shown in equations (4.11), (4.12), (4.13), (4.14), and (4.15). Positive superscripts (+) indicate maximum operating limits, while negative superscripts (-) indicate minimum operating limits.

\begin{align*}
    P_i^- & < P_i < P_i^+ \quad (4.11) \\
    Q_i^- & < Q_i < Q_i^+ \quad (4.12) \\
    E_n^- & < E_n < E_n^+ \quad (4.13) \\
    \delta_n^- & < \delta_n < \delta_n^+ \quad (4.14) \\
    \text{MVA}_k^- & < \text{MVA}_k < \text{MVA}_k^+ \quad (4.15)
\end{align*}

where $E_n$ is the voltage magnitude at bus $n$, $\delta_n$ is the voltage phase angle at bus $n$, and MVA$_k$ is the power flow of transmission branch $k$.

For renewable generation such as wind and solar, the high operating limit must not be greater than the forecast output for the time period from the centralized forecasting system. This constraint can be shown as

\begin{equation}
P_{ri}^+ \leq P_{ri\_forecast} \quad (4.16)
\end{equation}

where $P_{ri\_forecast}$ is the forecast output for the renewable generator $i$.

### 4.2.3 Linear Programming

In this dissertation, linear programming (LP) is utilized to perform the AC OPF. LP solves an optimization problem by maximizing or minimizing a linear objective function while
enforcing all system constraints, which are linear equality or linear inequality. All variables are associated with a sign restriction: nonnegative, unrestricted in sign (urs) [38]. In the AC OPF, LP is solved by minimizing the objective function in equation (4.8) and satisfying the constraints of system power balances and system operating limits as specified in section 4.2.2.

4.2.4 Power Flow Software

This research applies PowerWorld’s Simulator software [39] to run the optimal power flow. The software functions include optimal power flow, security constrained optimal power flow, contingency analysis, economic analysis, and power transfer distribution factor calculation.

4.3 Integration of Renewable Generation and Energy Storage in AC OPF

4.3.1 Study Process

The process starts by preparing a power flow base case representing the initial condition of an electric power system. The next step is incorporating renewable generators, such as wind and solar, into the existing system. Because renewable generators are not dispatched by the OPF, their costs are input in the AC OPF as zero. But the actual cost to the system is not zero; the system pays for renewable energy based on the LMP as shown in equation (4.2). The system operating cost of renewable generation will be calculated using equation (4.2), and added to the total system operating cost after performing the AC OPF.

Energy storage will also be added into the power flow case. Since there are two different system conditions of energy storage, charge, and discharge, storage output during charge and discharge will be specified. These should be determined by optimizing either cost, emissions, or other variables over time.

Figure 4.1 shows the process to study the effects of renewable generation and energy storage on GHG emissions. The AC OPF is performed first for the base case and then for
specified contingencies. If one of the contingencies is violated, the OPF dispatch process will reschedule the resources. An additional reserve unit may be required to ensure system reliability. If there is no violation, CO₂ emissions will be calculated according to MW output dispatched by AC OPF. Finally, the payments, based on LMPs, to new resources, such as new renewable generation and energy storage, will be calculated separately.

### 4.3.2 Capacity Credit

The system operator is required to have reserve generation operating in excess of the forecast load. The amount required varies among operating regions but is usually in the range of 5 to 12 percent of forecast peak load. The value of renewable generation as reserves is determined by capacity credits, but additional conventional generation is always needed to replace the potential loss of the renewable resource. Conventional reserve units, operating at less than full capacity, are assigned accordingly, and these represent an additional cost of using renewable generation.

Since renewable generation varies with the wind or solar resource, more renewable generation is required to replace conventional generation in order to ensure that the load is served. The specific amount of renewable generation required to replace one unit of conventional generation is based on its capacity credit, which is set by the system operator. For example, when using 33 percent capacity credit for wind generation, three MW of wind generation resources will be required to replace one MW of conventional fossil-fired generation. The capacity credits for each type of renewable generation will be different due to their unique nature of fuel sources.
Figure 4.1. Process to study effects of renewable and storage on GHG emissions.
4.3.3 Ancillary Services

To ensure that sufficient capacity is committed, ancillary services are usually assigned during day-ahead market and day-ahead reliability unit commitment when energy and ancillary services are evaluated and awarded. Generally, an independent system operator evaluates system load conditions for the next operating day and determines the required amount of ancillary services in MW for each hour of the next operating day [40]. Using mixed-integer programming to perform the energy and ancillary services co-optimization [41], the reliability unit commitment generates resource schedules and online unit status. In this dissertation, the study process simulates reserve units with consideration of integrated renewable generators and their capacity credits, as discussed in section 4.3.2.

4.3.3 Time Series

Performing OPF gives one “snapshot” of the power system conditions at an instant in time. To better represent variable characteristics of renewable generation, the charge and discharge of energy storage, and the CO$_2$ emissions from a system over a period, a series of OPF simulations are run with time-varying inputs. Simulated output of renewable generators are specified based on historical or simulated profiles of renewable resources. Hydroelectric generation and energy storage are scheduled outside the OPF and input as time series data. Electrical load demand also varies with time depending on time of day, season, and year. Load data are also represented as a set of points in time. This dissertation utilizes a time series of renewable generation output, hydroelectric and energy storage, and system load as input data to the OPF. Finally, a set of solutions for the specified time period will be obtained.
CHAPTER 5

STUDY CASES AND SIMULATION RESULTS

The methodology developed in Chapter 4 was applied to a number of study cases in order to investigate the effects of renewable generation and energy storage on GHG emissions. Section 5.1 presents the selected test system, the IEEE 24 bus reliability test system. System topology, fuel sources, and modifications are discussed. Section 5.2 describes the study cases that are based on different renewable output profiles, load profiles, and CO₂ prices. Solution types and number of time points are also considered in designing the study cases. Section 5.3 presents simulation results. The interpretation of the simulation results is presented in Section 5.4.

5.1 Test System

This dissertation utilizes the IEEE 24-bus reliability test system (RTS) to demonstrate the methodology. The IEEE RTS [42] was first developed by the Application of Probability Subcommittee of the Power Engineering Subcommittee in 1979 to be used as a power system in reliability analyses. The system was later updated in 1986 and 1996. The IEEE RTS has a total load of 2,850 MW and total generation of 3,405 MW. There are two voltage levels in the IEEE RTS: 138 kV and 230 kV.

Originally, the fuel sources of the IEEE 24-bus RTS generation consisted of hydro, nuclear, fossil coal, and fossil oil. However, this research replaces 951 MW of fossil oil with the same amount of capacity of fossil gas in order to incorporate fossil gas into the analysis. With total generation of 3,405 MW, the generating capacity of the new modified IEEE RTS is shown in Figure 5.1.
Figure 5.1. Generation capacity (MW) in the modified IEEE RTS.

5.2 Simulation Cases and Assumptions

Various study cases are designed based on different renewable generation profiles, system load profiles, CO\textsubscript{2} prices, solution types, and length of time simulated. The average fuel prices in the year 2008 [43] are used as the fuel costs for each generator in the IEEE RTS system (2.06 $/MBtu for coal, 9.34 $/MBtu for gas, and 16.56 $/MBtu for oil, according to average fuel prices from January 2008 to November 2008). Fuel cost for nuclear is 0.44$/MBtu, as per the average U.S. nuclear fuel price in 2006 [44]. The CO\textsubscript{2} emission factors are 215 lb/MBtu, 117 lb/MBtu, and 161 lb/MBtu for coal, gas, and oil, respectively [45]. Assumed CO\textsubscript{2} prices of zero and 50 $/ton are studied in the proposed cases. Capacity credits are calculated when wind or solar are integrated into the test system. In this research, capacity credit is assumed to be 25.2 percent for wind and 89.5 percent for solar, based on the calculated capacity credits in [46].

Renewable generators are added into the IEEE RTS in cases 1-9 to study their effect on GHG emissions. Three renewable generators, 100 MW capacity each, are connected to bus no. 8 of the IEEE RTS system through a new transmission line. The IEEE RTS with renewable generation is shown in Figure 5.2.
Figure 5.2. Modified IEEE reliability test system with renewable generation adapted from [47].
In order to calculate the system operating cost with renewable generation, a system forecasting fee is assumed to be 0.10 $/MWh, based on [5]. This research also applies 0.010 $/MWh of net deviation charge for electricity produced from renewable generation.

An energy storage system rated 10MW is added into the IEEE RTS in case 11 and located at the same bus as renewable generation. An annualized fixed operation and maintenance cost for the storage unit is assumed to be 15 $/kWh [36]. The storage is assumed to charge and discharge one time in each 24-hour period. The number of operating days for this storage is approximately 250 days per year.

The methodology solves the OPF solution for cases 1-9 and 11 to determine the MW dispatched output, locational marginal prices for each node, and total operating cost. Meanwhile, the security constrained optimal power flow (SCOPF) is run for case 10 to address security issue by considering contingencies. In this case, three contingencies are specified and included in the analysis. Each contingency is the loss of a transmission line in the power system. The three contingencies include loss of a transmission line from bus 15 to bus 24, a transmission line from bus 13 to bus 23, and a transmission line from bus 14 to bus 11.

The time series of renewable generation and system load are applied in each case. The simulation runs 24 time steps (hours) for daily load and generation profiles, and 8,784 time steps (hours) for year-round profiles. Table 5.1 summarizes the simulation cases and their detailed descriptions, including generation and load profiles, solution type, and CO₂ prices.
### TABLE 5.1
SIMULATION CASES AND DESCRIPTION

<table>
<thead>
<tr>
<th>Case No.</th>
<th>Renewable Generation Type</th>
<th>Profile</th>
<th>Load Profile</th>
<th>CO₂ Price ($/ton)</th>
<th>Solution Type</th>
<th>Number of Time Point (hour)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Wind</td>
<td>Low varying</td>
<td>Typical summer day</td>
<td>0</td>
<td>OPF</td>
<td>24</td>
</tr>
<tr>
<td>2</td>
<td>Wind</td>
<td>Medium varying</td>
<td>Typical summer day</td>
<td>0</td>
<td>OPF</td>
<td>24</td>
</tr>
<tr>
<td>3</td>
<td>Wind</td>
<td>High varying</td>
<td>Typical summer day</td>
<td>0</td>
<td>OPF</td>
<td>24</td>
</tr>
<tr>
<td>4</td>
<td>Wind</td>
<td>Low varying</td>
<td>Typical summer day</td>
<td>50</td>
<td>OPF</td>
<td>24</td>
</tr>
<tr>
<td>5</td>
<td>Wind</td>
<td>Medium varying</td>
<td>Typical summer day</td>
<td>50</td>
<td>OPF</td>
<td>24</td>
</tr>
<tr>
<td>6</td>
<td>Wind</td>
<td>High varying</td>
<td>Typical summer day</td>
<td>50</td>
<td>OPF</td>
<td>24</td>
</tr>
<tr>
<td>7</td>
<td>Solar</td>
<td>Summer day</td>
<td>Typical summer day</td>
<td>0</td>
<td>OPF</td>
<td>24</td>
</tr>
<tr>
<td>8</td>
<td>Solar</td>
<td>Summer day</td>
<td>Typical summer day</td>
<td>50</td>
<td>OPF</td>
<td>24</td>
</tr>
<tr>
<td>9</td>
<td>Wind</td>
<td>Year 2004</td>
<td>Scaled year 2004</td>
<td>50</td>
<td>OPF</td>
<td>8784</td>
</tr>
<tr>
<td>10</td>
<td>Wind</td>
<td>Year 2004</td>
<td>Scaled year 2004</td>
<td>50</td>
<td>SCOPF</td>
<td>8784</td>
</tr>
<tr>
<td>11</td>
<td>Wind/Storage</td>
<td>Medium varying</td>
<td>Typical summer day</td>
<td>0</td>
<td>OPF</td>
<td>24</td>
</tr>
</tbody>
</table>
The three different daily wind profiles listed in Table 5.1 are based on generation output data [48] from ERCOT’s wind generation resources and are used as the MW output of the new added wind power plants. The three daily wind patterns include low varying generation output, medium varying output, and high varying output.

The load profile that is used is a typical summer day load based on the ERCOT historical load data [49] for a summer day in 2008 and scaled down to the system load of the IEEE-RTS. Figure 5.3 shows plots of the typical summer day load profile versus the three wind-generation output profiles.

![Figure 5.3. Typical summer day load profile and three wind generation output profiles.](image)

Solar generation is added to the IEEE RTS in cases 7 and 8. The output of a solar power plant is much more predictable than that of a wind generator, because meteorological models predict clouds and sunlight much more accurately than wind. The solar power plant always generates output between sunrise and sunset unless there is a significant amount of clouds or other extreme weather conditions. In this research, a solar generation output profile is developed
and scaled, based on the output profile of a solar array in the ERCOT control area on a summer day, as described by [50]. Figure 5.4 presents the typical summer day load profile versus the solar profile.

Figure 5.4. Typical summer day load profile and a solar generation output profile.

Besides single-day simulations, simulations are also performed for a one-year span. In these annual simulations, the OPF and SCOPF are run for 8,784 time points, which represent the 8,784 hours of the year 2004. ERCOT’s 2004 historical load data [49] is scaled down and applied as a year-round load pattern, including MW and MVar load for each load bus of the IEEE RTS. Figure 5.5 presents the annual scaled MW load profile that is used in this dissertation. Wind generation hourly output data recorded in the year 2004 [48] is applied as the MW output of added wind generation resources. Figure 5.6 illustrates annual wind power output of a simulated wind power plant.
Figure 5.5. Annual scaled system load profile.

Figure 5.6. Annual wind generation output profile.
5.3 Simulation Results

5.3.1 Integration of Wind Generation into Zero CO\(_2\) Price Test System

Case 1, case 2, and case 3 represent a test system with zero CO\(_2\) price with the integration of various wind profiles. Generation dispatch without any renewable generation in the zero CO\(_2\) price test system is presented in Figure 5.7.

![Generation dispatch without renewable generation](image)

Figure 5.7. Generation dispatch without renewable generation installed.

The IEEE RTS system consists of several generation units with different fuel types. In this dissertation, the modified generation mix includes the following: 800 MW of nuclear power plants, 300 MW of hydro power plants, 1,274 MW of coal-fired power plants, 951 MW of gas-fired power plants, and 80 MW of petroleum oil combustion turbine plants.

Figure 5.7 shows the system dispatch for a typical summer day load without renewable generation installed. Nuclear power plants are dispatched as base load units, which always run at the rate of their maximum output. Thus the output of nuclear plants are seen as constantly flat during the day. Hydro plants, however, are committed usually only on peak-load hours of the day.
due to the limitation of the amount of water available to generate. In this model, the hydro units start to operate at 3 PM and continue running until 8 PM. Coal-fired power plants follow daily load demand by raising their output during on-peak hours and reducing their output during off-peak hours. The coal-fired power plants, however, slightly drop their output due to congestion caused by the hydro plants. The combustion turbine plants are not dispatched due to the high fuel price of petroleum oil.

Figure 5.8 shows the marginal price at the bus where renewable generation will be installed in later simulations. As seen from this plot, the congestion occurred during the peak period from 3 PM to 8 PM. Congestion costs in the locational marginal price are about zero for most of the day until hydro plants start to operate. Congestion costs increased to about $50 per MWh when hydro units are committed. In this lossless model, the locational marginal price consists of marginal congestion price and marginal energy price. Locational marginal prices are about $18.93 to $24.91 per MWh during the off-peak period and increase to $110.43 per MWh during the on peak period because of congestion caused by the hydro units.

![Figure 5.8. Marginal price at renewable generation bus before renewables are installed.](image-url)
5.3.2 Case 1: Low Varying Wind Pattern, CO$_2$ Price=$0$/Ton, 24-Hour Period

Simulation results for case 1 are presented in Figures 5.9 to 5.12. Changes in system operating cost as installed wind capacity is increased are shown in Figure 5.9. Numbers specified along the plot of total system operating cost in Figure 5.9 are changes in the operating cost in U.S. dollars as each 100 MW of wind is integrated into the existing system. A minus sign indicates that the integration of wind generators reduces the system operating cost. The total system operating cost consists of the fuel-emission cost and renewable cost. In this case, the fuel-emission cost indicates only fuel cost of fossil-fired generators and nuclear generators since the CO$_2$ emission cost is set at zero.

![Figure 5.9. Changes in system operating cost in case 1.](image)

Figure 5.9 shows changes in CO$_2$ emissions in the same case. Numbers shown in the plot are changes in CO$_2$ emissions as each 100 MW of wind is connected to the system. Figure 5.11 shows generation dispatch versus time period when 300 MW of wind are installed in the system. Figure 5.12 presents marginal price with 300 MW installed wind in case 1. This figure includes plots of locational marginal price, marginal energy price, and marginal congestion price. The marginal loss price is zero as this system is assumed to be a lossless system.
Figure 5.10. Changes in CO₂ emissions in case 1.

Figure 5.11. Generation dispatch with 300 MW installed wind in case 1.
5.3.3 Case 2: Medium Varying Wind Pattern, CO₂ price=$0/Ton, 24-Hour Period

Case 2 utilizes a medium varying wind profile and zero CO₂ price. A set of 24-hour time steps of system load and wind generation are input into the optimal power flow analysis. The simulation results of case 2 are presented in Figures 5.13 to 5.16. Changes in system operating cost in this case are shown in Figure 5.13. Figure 5.14 shows changes in CO₂ emissions versus output capacity of additional wind installed. Figure 5.15 presents generation dispatch versus time period in a day with 300 MW of wind installed into the existing system. Figure 5.16 shows marginal prices with 300 MW installed wind in case 2.
Figure 5.13. Changes in system operating cost in case 2.

Figure 5.14. Changes in CO₂ emissions in case 2.
Figure 5.15. Generation dispatch with 300 MW installed wind in case 2.

Figure 5.16. Marginal price with 300 MW installed wind in case 2.
5.3.4 Case 3: High Varying Wind Pattern, CO₂ Price=$0/Ton, 24-Hour Period

Case 3 applies a high varying wind profile and zero CO₂ price. As in case 1 and case 2, a set of 24-hour time steps of system load and wind generation are input into the optimal power flow analysis. Figures 5.17 to 5.20 illustrate the simulation results of case 3. Changes in system operating cost in this case are shown in Figure 5.17. Total system operating consists of fuel-emission cost and renewable cost. Like previous cases, the fuel-emission cost is only the fuel cost of fossil-fired generators due to zero CO₂ emission cost. Figure 5.18 shows changes in CO₂ emissions versus output capacity of additional wind installed. Figure 5.19 presents generation dispatch versus time with 300 MW of wind installed. Figure 5.20 illustrates marginal price with 300 MW installed wind.

![Figure 5.17. Changes in system operating cost in case 3.](image-url)
Figure 5.18. Changes in CO₂ emissions in case 3.

Figure 5.19. Generation dispatch with 300 MW installed wind in case 3.
5.3.5 Integration of Wind Generation into Given CO₂ Price Test System

Case 4, case 5, and case 6 apply a CO₂ price at $50/ton with the three different wind profiles. Figure 5.21 presents the generation dispatch of the test system during the 24-hour time period without wind plants. Figure 5.22 shows the marginal price at the wind bus before wind is installed.

Figure 5.20. Marginal price with 300 MW installed wind in case 3.

Figure 5.21. Generation dispatch with $50/ton CO₂ price.
5.3.6 Case 4: Low Varying Wind Pattern, CO\textsubscript{2} Price= $50/Ton, 24-Hour Period

Case 4 uses a low varying wind profile and a CO\textsubscript{2} price of $50/ton. A set of 24-hour time steps of system load and wind generation are input into the optimal power flow analysis. The simulation results of case 4 are shown in Figures 5.23 to 5.26. Changes in system operating cost in this case are shown in Figure 5.23. Total system operating cost includes the fuel-emission cost and renewable cost. Unlike the first three cases, the fuel-emission cost of case 4 consists of two components: fuel cost and emission cost. Figure 5.24 shows changes in CO\textsubscript{2} emissions versus output capacity of additional wind installed. Generation dispatch based on time period with 300 MW of wind installed is shown in Figure 5.25. Figure 5.26 presents the marginal price with 300 MW installed wind in case 4.
Figure 5.23. Changes in system operating cost in case 4.

Figure 5.24. Changes in CO₂ emissions in case 4.
Figure 5.25. Generation dispatch with 300 MW installed wind in case 4.

Figure 5.26. Marginal price with 300 MW installed wind in case 4.
5.3.7 Case 5: Medium Varying Wind Pattern, CO\textsubscript{2} Price= $50/ton, 24-Hour Period

Case 5 applies a medium varying wind profile and a CO\textsubscript{2} price of $50/ton. A set of 24-hour time steps of system load and wind generation are input into the optimal power flow analysis. Figures 5.27 to 5.30 show the simulation results of case 5. Changes in system operating cost in this case are presented in Figure 5.27. Total system operating cost consists of fuel-emission cost and renewable cost, the same as in case 4. Figure 5.28 shows changes in CO\textsubscript{2} emissions versus output capacity of additional wind installed. Figure 5.29 presents generation dispatch versus 24-hour time steps for a typical summer day with 300 MW of wind installed. Figure 5.30 presents marginal prices with 300 MW installed wind in case 5.

![Graph showing system operating cost changes in case 5.](image)

Figure 5.27. Changes in system operating cost in case 5.
Figure 5.28. Changes in CO$_2$ emissions in case 5.

Figure 5.29. Generation dispatch with 300 MW installed wind in case 5.
5.3.3 Case 6: High Varying Wind Pattern, CO\textsubscript{2} Price= $50/Ton, 24-Hour Period

Case 6 uses a high varying wind profile and a CO\textsubscript{2} price of $50/ton. A set of 24-hour time steps of system load and wind generation are input into the optimal power flow analysis. Simulation results of case 6 are shown in Figures 5.31 to 5.34. Figure 5.31 illustrates changes in system operating cost versus capacities of wind generators installed. Figure 5.32 shows changes in CO\textsubscript{2} emissions versus output capacity of additional wind installed. Figure 5.33 presents generation dispatch based on 24-hour time periods with 300 MW of wind installed. Figure 5.34 shows marginal prices with 300 MW wind plants in case 6.
Figure 5.31. Changes in system operating cost in case 6.

Figure 5.32. Changes in CO\textsubscript{2} emissions in case 6.
Figure 5.33. Generation dispatch with 300 MW installed wind in case 6.

Figure 5.34. Marginal price with 300 MW installed wind in case 6.
5.3.9 Case 7: Solar, CO$_2$ Price= $0$/Ton, 24-Hour Period

Integration of solar generation into the IEEE RTS is investigated in case 7 and case 8. Case 7 applies solar generation and zero CO$_2$ price. A set of 24-hour time steps of system load and solar generation are input into the optimal power flow analysis. The simulation results of case 7 are shown in Figures 5.35 to 5.38. Figure 5.35 shows changes in system operating cost versus MW capacities of wind generation resources. Figure 5.36 presents changes in CO$_2$ emissions versus output capacity of additional solar installed. Figure 5.37 presents generation dispatch versus time period when 300 MW wind are integrated into the IEEE RTS. Figure 5.38 presents marginal price with 300 MW installed solar in case 7.

![Figure 5.35. Changes in system operating cost in case 7.](image-url)
Figure 5.36. Changes in CO$_2$ emissions in case 7.

Figure 5.37. Generation dispatch with 300 MW installed solar in case 7.
5.3.10 Case 8: Solar, CO₂ Price= $50/Ton, 24-Hour Period

Case 8 utilizes solar generation and a CO₂ price of $50/ton. This case performs OPF with the 24 time step data series of system load and solar generation output. Figures 5.39 to 5.42 illustrate the simulation results of case 8. Figure 5.39 presents changes in system operating cost in this case. Figure 5.40 illustrates changes in CO₂ emissions versus output capacity of additional solar installed. Generation dispatch vs. time period is shown in Figure 5.41 with 300 MW of solar installed. Figure 5.42 shows the marginal prices with 300 MW installed solar in case 8.

Figure 5.38. Marginal price with 300 MW installed solar in case 7.
Figure 5.39. Changes in system operating cost in case 8.

Figure 5.40. Changes in CO$_2$ emissions in case 8.
Figure 5.41. Generation dispatch with 300 MW installed solar in case 8.

Figure 5.42. Marginal price with 300 MW installed solar in case 8.
5.3.11 Case 9: 2004 Wind Profile, CO₂ Price= $50/Ton, 8784 Hour Period, OPF Solution

Case 9 applies the wind profile and system load profile of the whole year 2004. A total of 8,784 time steps of data, representing the 8,784 hours of year 2004, of wind generation and load, are inputs of the analysis. OPF is again used as the solution tool in this study case. Figure 5.43 shows changes in system cost in case 9 for operating this test system for the whole year. Figure 5.44 presents changes in CO₂ emissions due to the integration of wind generators. Generation dispatch in this case is presented in Figure 5.45.

![Figure 5.43. Changes in system operating cost in case 9.](image-url)
Figure 5.44. Changes in CO₂ emissions in case 9.

Figure 5.45. Generation dispatch in case 9.
5.3.12 Case 10: 2004 Wind Profile, CO₂ Price = $50/Ton, 8784 Hour Period, SCOPF Solution

The annual wind profile and system load are again applied to case 10. Unlike previous cases, this case uses SCOPF as a solution tool with consideration of contingencies. Three contingencies, each based on the loss of a different transmission line, are specified. Figure 5.46 shows changes in system cost in Case 10 for operating the system for the whole year. Figure 5.47 presents changes in CO₂ emissions due to the integration of wind generators.

![Figure 5.46. Changes in system operating cost in case 10.](image-url)
Figure 5.47. Changes in CO$_2$ emissions in case 10.

Figure 5.48. System operating cost in case 9 and case 10.
5.3.13 Case 11: Medium Varying Wind Profile with Energy Storage, CO$_2$ Price= $0/Ton

An energy storage unit along with medium varying wind profile are applied in this case. Lead acid batteries rated 10 MW and 120 MWh, are connected into the same bus as the wind generators. A 12-hour battery charge/discharge time is assumed in this study. The storage charges from 9:00 PM to 9:00 AM and then discharges electricity back to the grid from 9:00 AM to 9:00 PM. The unit operates one time per day and 250 days per year. The operating cost for energy storage is calculated based on the cost modeling presented in Chapter 4. The analysis performs OPF for a 24 hour time period for a typical summer day. Figure 5.50 shows changes in system operating cost in case 11. Figure 5.51 presents change in emissions in the same case. The system operating cost and total emissions of case 11 and case 2, the same case with and without storage, are compared in Figure 5.52 and Figure 5.53, respectively.
Figure 5.50. Changes in system operating cost in case 11.

Figure 5.51. Changes in CO₂ emissions in case 11.
Figure 5.52. System operating cost in case 2 and case 11.

Figure 5.53. Total CO$_2$ emissions in case 2 and case 11.
All results are summarized in Tables 5.1 and 5.2.

**TABLE 5.2**

TOTAL CO₂ EMISSIONS AND CHANGE

<table>
<thead>
<tr>
<th>Case No.</th>
<th>Total CO₂ Emissions (tons)</th>
<th>Change of CO₂ Emissions (tons)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0 MW Renewable Installed</td>
<td>100 MW Renewable Installed</td>
</tr>
<tr>
<td>1</td>
<td>30,832</td>
<td>29,503</td>
</tr>
<tr>
<td>2</td>
<td>30,832</td>
<td>30,217</td>
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<tr>
<td>3</td>
<td>30,832</td>
<td>30,456</td>
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<tr>
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<td>11</td>
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</table>
# TABLE 5.3

**SYSTEM OPERATING COST AND CHANGE**

<table>
<thead>
<tr>
<th>Case No.</th>
<th>0 MW Renewable Installed</th>
<th>100 MW Renewable Installed</th>
<th>200 MW Renewable Installed</th>
<th>300 MW Renewable Installed</th>
<th>1st 100MW Renewable Installed</th>
<th>2nd 100MW Renewable Installed</th>
<th>3rd 100MW Renewable Installed</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1,351,283</td>
<td>1,337,318</td>
<td>1,319,155</td>
<td>1,315,103</td>
<td>13,966</td>
<td>18,163</td>
<td>4,052</td>
</tr>
<tr>
<td>2</td>
<td>1,351,283</td>
<td>1,340,967</td>
<td>1,332,659</td>
<td>1,316,205</td>
<td>10,316</td>
<td>8,309</td>
<td>16,453</td>
</tr>
<tr>
<td>3</td>
<td>1,351,283</td>
<td>1,342,395</td>
<td>1,333,257</td>
<td>1,328,747</td>
<td>8,889</td>
<td>9,137</td>
<td>4,511</td>
</tr>
<tr>
<td>4</td>
<td>2,872,811</td>
<td>2,852,572</td>
<td>2,835,404</td>
<td>2,829,446</td>
<td>20,239</td>
<td>17,168</td>
<td>5,958</td>
</tr>
<tr>
<td>5</td>
<td>2,872,811</td>
<td>2,858,361</td>
<td>2,847,077</td>
<td>2,839,298</td>
<td>14,450</td>
<td>11,284</td>
<td>7,779</td>
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<tr>
<td>6</td>
<td>2,872,811</td>
<td>2,860,381</td>
<td>2,848,784</td>
<td>2,841,974</td>
<td>12,430</td>
<td>11,597</td>
<td>6,810</td>
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<td>7</td>
<td>1,351,283</td>
<td>1,330,587</td>
<td>1,312,033</td>
<td>1,309,308</td>
<td>20,696</td>
<td>18,555</td>
<td>2,724</td>
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<tr>
<td>8</td>
<td>2,872,811</td>
<td>2,846,217</td>
<td>2,821,432</td>
<td>2,805,262</td>
<td>26,594</td>
<td>24,785</td>
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<td>643887780</td>
<td>639363928</td>
<td>636796507</td>
<td>5,668,446</td>
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<td>2,567,422</td>
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<td>5,214,031</td>
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<tr>
<td>11</td>
<td>1,347,216</td>
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<td>1,328,462</td>
<td>1,312,356</td>
<td>10,692</td>
<td>8,062</td>
<td>16,105</td>
</tr>
</tbody>
</table>
5.4 Interpretation of Results

Results of the simulations demonstrate how integration of low carbon emission generation affects the test system. Effects include system dispatch, emissions, cost, and reliability. Effects of energy storage are also discussed in this section.

5.4.1 System Dispatch

When renewable generators are integrated into the system, they generate inconstant output based on available fuels from nature such as wind and sunlight. These low carbon generation outputs can change at any time. Their output is considered a must-take resource and are unavailable for the automatic generator control (AGC) to adjust.

Output from nuclear power plants is almost always constant, and nuclear plants have relatively low operating costs. Nuclear units are assigned to run at full capacity all the time, with an occasional exception of coast down at the end of a fuel cycle. As a result, the generation dispatch of nuclear power plants is constantly flat throughout the day.

Hydro power plants are normally scheduled outside the system dispatch. Unlike nuclear power plants, hydro plants cannot run all day long due to limitations in the amount of water, depending on seasonal climate and geography. Hydro plants in the system simulated for this dissertation operate only during on-peak load, which is from 3:00 PM to 8:00 PM.

Due to their high fuel price, combustion plants burning petroleum oil are never dispatched in this model. The outputs of these generators are zero all the time. For some control areas, generators with oil as fuel will be dispatched only when gas-fired generators are not available.

As renewable generators (wind generators or solar plants) are integrated into the IEEE RTS, the system dispatch of coal-fired power plants and gas-fired power plants is reduced. Coal-
fired power plants usually run as base load units but follow changing load as needed. In the simulation results, coal-fired generators drop their output during off-peak load when all gas-fired generation has been reduced to low or zero output. The coal units then raise their output to follow load as it increases. In Figure 5.7, when no wind generation is installed, coal-fired plants drop their total output slightly below 800 MW at 6:00 AM. With integration of wind, coal-fired power plants lower their output even more during off-peak load because of the additional energy contributed to the system by the wind generators. According to Figure 5.54, dispatched generation of coal plants drop to 677 MW, 603 MW, and 503 MW at off-peak load with integration of wind at 100 MW, 200 MW, and 300 MW, respectively. Although it is unusual to reduce the output of a coal-fired generator below 50 percent of its rated capacity, some power plants can go below 50 percent using special operating procedures and plant designs.

As load increases during the day, coal-fired power plants increase their output to meet the demand. These units, however, slightly drop their outputs during the on-peak period due to congestion caused by hydro plants. The MW output of coal-fired generation units at peak load are flattened due to the integration of low varying wind output in case 1 and case 4. In these cases, wind generation relieves some of the congestion caused by hydro units. Wind generation is low during the congestion period in the medium-varying and high-varying wind profiles, however, much less congestion relief is provided, and coal output is still reduced during peak load in these cases. The generation dispatch of coal responds differently with each generation output profile of renewable generation. Figure 5.54 presents the generation dispatch of coal-fired generation units with different wind capacity installed for case 1. Plots for other cases are shown in Appendix U.
Figure 5.54. Generation dispatch for coal-fired power plants in case 1.

Gas-fired generating units in this simulation are used to support other generators to meet load demand. Based on their fuel price, which is higher than coal or nuclear units, they are dispatched at peak demand of the day, after all lower-cost gas and coal units are already operating at full capacity. With the integration of renewable generators, gas-fired generating units lower their output during the peak period. Figure 5.55 shows generation dispatch for gas-fired power plants in case 1. Each additional unit of renewable generation further reduces the output of the gas fired plants. Similar to the economic dispatch of coal-fired power plants, system dispatch responds differently with each output profile of renewable generation. Generation dispatch of gas fired generation units for other cases are shown in Appendix V.
5.4.2 Emissions

Based on the previous plots of changes in CO$_2$ emissions, an integration of low carbon emission generators certainly reduces CO$_2$ emissions. The reduction of CO$_2$ emissions, however, is not proportional to each MW capacity of renewable generators installed. As shown in the simulation results, the change in CO$_2$ emissions for each step of 100 MW installed wind or solar is not linear. This phenomenon is explained by several factors that affect system dispatch. These factors include fossil-fired generating plant design, the need for more operating gas-fired reserve units as renewable penetrations increase, and changes in transmission congestion.

According to the results, the reduction in CO$_2$ emissions decreases for every 100 MW increase in wind generation. In case 1, reductions of CO$_2$ emissions are 1,329 tons, 1,253 tons, and 1,214 tons for 100 MW, 200 MW, and 300 MW wind installed, respectively. For each increasing one hundred megawatts of wind, case 2 shows 615 tons, 571 tons, and 557 tons of CO$_2$ emission reduction while case 3 shows 376 tons, 360 tons, and 356 tons, respectively. For
the system costing $50/ton CO₂, case 4 shows 1,362 tons, 1,281 tons, and 1,201 tons of CO₂ reduction, while CO₂ emission reductions in case 5 are 619 tons, 580 tons, and 560 tons when the system is integrated with 100 MW, 200 MW, and 300 MW of wind, respectively. Case 6 shows reductions of 378 tons, 363 tons, and 354 tons. Running the simulation for a whole year confirms this trend. The CO₂ emission reductions of case 9 are 345,285 tons, 318,844 tons, and 300,539 tons further reduction for each additional 100 MW wind installed. Case 10 shows 354,219 tons, 323,885 tons, and 304,142 tons, for 100 MW, 200 MW, and 300 MW wind installed, respectively. Variations among the cases are due to the varying amounts of energy produced by the different wind profiles.

Integration of solar power plants, however, produces a different trend of CO₂ emission reduction. CO₂ emission reductions for case 7 are 279 tons, 331 tons, and 350 tons, while case 8 shows a reduction of 283 tons, 323 tons, and 345 tons for 100 MW, 200 MW, and 300 MW of solar power plants, respectively. For this system, each 100 MW of solar produces more CO₂ reductions than the previous 100 MW. This is because as more solar generation is added, natural gas generators can be turned off, because of the higher capacity credit of solar energy. The reductions obtained from solar differ from those of wind cases because the total energy produced is different in each case.

Figure 5.56 shows the total CO₂ emissions of a zero CO₂ price system with different installed renewable types and profiles. According to this plot, the existing power system with low varying wind emits the lowest CO₂. When integrated with solar or the high varying wind profile, the test system emits higher CO₂. Similar trends can be observed in the case with a $50/ton CO₂ price, as shown in Figure 5.57. Little change is seen when a CO₂ price of $50/ton is added because the solar and wind energy do not change, and $50/ton is not high enough for this system
to significantly shift from coal- to gas-fired generation. Not shown in this simulation, however, is the incentive that the CO\textsubscript{2} price presents to build new solar and wind generators. This is reflected in higher LMPs paid to renewable generators, which are presented in section 5.4.3.

Figure 5.56. CO\textsubscript{2} emissions in a zero CO\textsubscript{2} price system.

Figure 5.57. CO\textsubscript{2} emissions in a $50/ton CO\textsubscript{2} price system.
Case 11 analyzes how energy storage combined with renewables affects system operations and CO₂ emissions. Storage rated 10 MW and 120 MWh is added to the medium-varying profile wind generation case, case 2. Figure 5.53 compares total CO₂ emissions in case 11 and case 2. Both cases utilize the same conditions, but there is no energy storage applied to case 2. In case 11, storage charges from 9:00 PM to 9:00 AM and then discharges electricity back to the system from 9:00 AM to 9:00 PM. According to Figure 5.53, CO₂ emissions in case 11 are slightly higher than the emissions in case 2.

In case 11, more MW capacity of coal-fired generating units, which have higher CO₂ emissions factors, are dispatched to charge the battery energy storage unit at night. Energy storage then is reducing gas-fired generation during the day as it discharges electricity back to the grid. As a result, a net increase in CO₂ emissions is observed. If it is desired to use storage to reduce CO₂ emissions, its charge and discharge cycles will have to be optimized for that purpose. To obtain more accurate results, efficiency of the energy storage unit should be considered into the analysis.

5.4.3 System Operating Costs

System operating cost in this research consists of two major components: fuel-emissions cost, which is the total cost of fuel and emissions charges, and renewable generation cost, which only includes payments to the renewable generator, not the capital cost of the generator. As the MW capacity of installed renewable generation increases, the fuel-emission cost decreases due to less MW capacity of the conventional generation dispatched. The renewable generation cost increases when renewable generators produce more electricity. Overall, the system operating cost decreases as the amount of renewable generators installed increases. Similar to CO₂ emissions,
the changes in system operating cost are not linear with installed capacity. The factors involved in this issue are the same factors that affect CO₂ emissions.

The type of renewable resources and availability of wind or solar resources, which determines the generation output profiles, influences the system operating cost. Figure 5.58 illustrates the system operating with different renewable generators. The operating cost of the solar-integrated system is the lowest, because gas-fired generators were shut down because of solar’s high capacity factor. The system with a low-varying wind profile has a lower operating cost than the systems with medium-varying and high-varying wind profiles, because the low-varying profile results in the most energy produced by wind. The operating cost for the system with high varying wind profile is the highest, because it produced the least energy.

With the high capacity credit of solar, fewer gas-fired generators are committed as reserves, and as a result, lower overall operating costs are observed in case 7 and case 8. Operating costs with wind are affected by the amount of energy generated, when it is generated, and what types of generation it offsets. The low-varying wind profile in case 1 and case 4 has the highest energy production of the three wind cases, so it offsets a large amount of fossil-fired generation, giving the greatest reduction in CO₂ emissions and operating costs of the three cases. Considering the time when wind energy is generated, the low-varying wind profile also relieves congestion from 3:00 PM to 8:00 PM when hydro power generators operate, further reducing operating costs by reducing congestion costs. The medium-varying wind profile in case 2 and case 5, and the high-varying wind profile in case 3 and case 6, however, provide little congestion relief because there are very low wind outputs during the congestion period.

Higher system operating costs are seen in the system with a $50/ton CO₂ price when compared to those of the system with $0/ton CO₂ price, because that CO₂ price must be paid on
coal and gas generation, and because wind and solar are paid the higher LMP that results from the CO\textsubscript{2} price. Figure 5.59 shows system operating cost for a $50/ton CO\textsubscript{2} price system. Based on this figure, the system with solar has the lowest operating cost, while the systems with higher-varying profiles have higher system operating costs.

The operating cost of the system integrated with energy storage is analyzed in case 11. Figure 5.52 compares system operating costs in case 11 and case 2 to illustrate the difference in the system with and without energy storage. According to the results, the system operating cost in case 11 is lower than the operating cost in case 2. This is because the storage is charged at night from low-cost coal-fired generation, and when it is discharged during the day, it reduces the higher-cost gas-fired generation. Operation and maintenance of storage is calculated and added into the generating costs of some generating units dispatched to charge it during the charge cycle.

An alternative way of calculating the operating cost of energy storage, in which storage pays the LMP for energy as it charges, and then is paid the LMP as it discharges, is proposed in Chapter 4. If the storage unit is charged during low-cost times and discharged during high-cost times, this method will result in higher income for the storage owner but lower benefits for the system. System costs will still decrease, however, if LMPs are reduced by the discharging storage during high-cost times.

To calculate system operating costs of storage, the status of ownership is a very important issue. If energy storage is owned by a generator, the generation owner can decide when to charge the storage from its own generation. It can then bid stored energy into the market and be dispatched by the independent system operator as another generator, for which it will be paid the market price. Alternately, if energy storage is owned by a third party, independent of other
generation, the owner will pay for energy used to charge the unit and be paid as the system operator schedules it to discharge, both at market rates.

Figure 5.58. System operating cost for zero CO$_2$ price system for 24-hour period.

Figure 5.59. System operating cost for given CO$_2$ price system for 24-hour period.
5.4.4 Reliability and Security

Although GHG policies and standards encourage the power industry to reduce GHG emissions, maintaining the reliability of an electric power system is a must. A big challenge in power system operation is to continuously balance generation and load demand, because a power system has almost no storage of electricity. Committing more variable generators into a power system requires more generating units to run as a reserve. This research considers different capacity credits for wind and solar energy. The methodology can utilize various capacity credits and other reliability factors.

Contingency analysis is a tool to evaluate the reliability of system operations. A system operator may perform the contingency analysis for some particular contingencies to ensure security of the system. In case 10, three contingencies are considered in addition to the base case. Case 9 applies the same conditions, except there is no consideration of contingencies. If any of the contingencies result in outages or overloads, the generation is redispatched to bring all components into compliance. Figure 5.48 compares system operating costs of the base case and the security-constrained case that can survive contingencies. According to the figure, the system with contingencies built into its optimization solution (SCOPF) has a higher system operating cost than that of the system using normal OPF. The extra cost is to ensure a secure system.

Considering contingencies in system operations also affects CO₂ emissions. Figure 5.49 compares plots of CO₂ emissions in case 9 (OPF) and case 10 (SCOPF). Based on these graphs, CO₂ emissions in case 10 are slightly higher than the emissions in case 9. In case 10, more generation units with higher CO₂ emissions factors are dispatched to withstand contingency conditions.
5.4.5 Renewable Pricing and Locational Marginal Price

Renewable generators are paid the locational marginal price at the bus where it is connected. LMPs are relatively low during the off-peak period and then start to increase when load demand increases. Congestion prices are close to zero in the morning and then increase when hydro power plants are committed into the system, thus causing congestion. Installation of wind generation helps relieve this congestion, especially in the low-varying wind profile, which provides a large amount of wind generation during the congestion period. As a result, LMPs are significantly lower on peak in case 1 and case 4. Solar generation at 200 MW and 300 MW, however, raises LMPs during the peak period. This is because a different set of generating units are committed for solar due to its higher capacity credit than wind, and these have not relieved congestion and resulted in higher LMPs. This limitation of the methodology can be improved by incorporating optimal unit commitment to generate an optimal resource allocation for the available generators. Figure 5.60 shows LMPs with various MW capacities of wind integration in case 1. The graphs for other cases are shown in Appendix E.

![Figure 5.60. Locational marginal price in case 1.](image-url)
Appendices A through S present generation dispatch, marginal prices, and changes in generation for the 11 cases. Changes in locational marginal prices are shown in Appendix T. Changes in the dispatch of coal-fired generators are presented in Appendix U. Appendix V shows changes in the dispatch of gas-fired generators.
CHAPTER 6
CONCLUSIONS AND FUTURE WORK

6.1 Conclusions

This dissertation developed system operating cost models for renewable generation and energy storage. It also developed a new methodology to be used to investigate how low carbon emission generation and energy storage affect the GHG emissions of electric power systems. The dissertation addressed two important related issues: system reliability and system operating cost. Based on the methodology developed, the simulation results, and the interpretation of those results, the conclusions of this dissertation follow:

• The integration of renewable generation reduces CO$_2$ emissions since it offsets fossil-fired generators in an electric power system. A running fossil-fired generator, either as a spinning reserve unit or low dispatched unit, still emits CO$_2$ emissions, even though it is running at zero MW. The emissions of reserved units, therefore, must be considered in the overall emissions of an electric power system.

• The integration of low carbon emission generation tends to reduce system operating cost due to lower generation dispatched from fossil-fired generators. The system operator still must consider the operating cost of renewable generators, which is assumed to be the LMP paid for the energy produced, in the overall system operating cost. The operating cost of reserve fossil-fired generators running at zero or low output must be considered in the overall cost.

• Each increment of additional capacity of renewable generation installed reduces CO$_2$ emissions and also system operating cost. However, the change of emissions and system operating cost are not proportional to the additional capacity of renewable generation
installed due to complexities of an electric power system. These complexities include generation characteristics (ramp rates and cost function), transmission congestion, and the number of fossil-fired generators on-line as reserve units.

- The system operating cost model for renewable generation is able to properly represent the special characteristics of these low carbon emission generators.

- The proposed operating cost model for energy storage can also be used to verify its effects on overall system cost and emissions. As energy storage is dispatched in the example, it decreases operating costs but increases CO₂ emissions. It could be redispached to decrease emissions instead. Both depend on the charge and discharge schedule, which must be set to optimize either cost, emissions, or other parameters.

- The methodology can be used to investigate an electric power system with integrated renewable generation and energy storage. The methodology has the ability to consider several factors and unique characteristics of renewable generation, energy storage, and the transmission system. This approach can be performed by using any commercial or academic SCOPF software.

- According to the simulation results, generation output profiles of low carbon emission generation significantly affect total CO₂ emissions of an electric power system.

- Wind generation has a significantly lower capacity credit than solar, because wind is more variable and less predictable than solar. Solar’s higher credit reduces the need for other reserve units, which can lower costs and emissions, and produces significantly different results between solar and wind generators. Reserve units calculations were done manually for this research, but must be done using optimal unit commitment techniques for more accurate results.
• Any energy generated by wind or solar generators is almost always purchased by the power system, so CO₂ prices have no effect on the operation of installed wind and solar generation. A price on CO₂ does, however, provide an incentive to build new solar and wind generators, because increased generating costs from fossil-fired generators results in higher payments to renewable generators.

6.2 Future Work

The following future work, using the models and methodology developed in this dissertation, is recommended:

• Obtain real power system data from the Western Electricity Coordinating Council (WECC) system, CAISO, or ERCOT. Apply the methodology to investigate the system with additional renewable generation, energy storage, and new transmission lines.

• Address the issue of location of new renewable generators and energy storage in the system. Analyze the geographical area of the system.

• Study the effects of the construction of new transmission lines to move the generation of remote renewable generation to electric loads in highly populated areas. Address the issue of congestion of transmission lines.

• Utilize optimal unit commitment prior to OPF and SCOPF studies. Unit commitment is generally performed by mixed-integer programming.

• Vary the different schedules of energy storage to optimize CO₂ emissions, and consider efficiency of the storage system.
LIST OF REFERENCES


LIST OF REFERENCES (continued)


LIST OF REFERENCES (continued)


LIST OF REFERENCES (continued)


APPENDIX A

ECONOMIC DISPATCH (CASE 1)

Figure A.1. No wind.

Figure A.2. 100 MW wind installed.

Figure A.3. 200 MW wind installed.

Figure A.4. 300 MW wind installed.
APPENDIX B

MARGINAL PRICES (CASE 1)

Figure B.1. No wind.

Figure B.2. 100 MW wind installed.

Figure B.3. 200 MW wind installed.

Figure B.4. 300 MW wind installed.
APPENDIX C

CHANGE IN GENERATION

Figure C.1. Case 1.

Figure C.2. Case 2.

Figure C.3. Case 3.

Figure C.4. Case 4.
APPENDIX C (continued)

Figure C.5. Case 5.

Figure C.6. Case 6.

Figure C.7. Case 7.

Figure C.8. Case 8.
Figure C.9. Case 9.

Figure C.10. Case 10.

Figure C.11. Case 11.
APPENDIX D

ECONOMIC DISPATCH (CASE 2)

Figure D.1. No wind.

Figure D.2. 100 MW wind installed.

Figure D.3. 200 MW wind installed.

Figure D.4. 300 MW wind installed.
APPENDIX E

MARGINAL PRICES (CASE 2)

Figure E.1. No wind.

Figure E.2. 100 MW wind installed.

Figure E.3. 200 MW wind installed.

Figure E.4. 300 MW wind installed.
APPENDIX F

ECONOMIC DISPATCH (CASE 3)

Figure F.1. No wind.

Figure F.2. 100 MW wind installed.

Figure F.3. 200 MW wind installed.

Figure F.4. 300 MW wind installed.
APPENDIX G

MARGINAL PRICES (CASE 3)

Figure G.1. No wind.

Figure G.2. 100 MW wind installed.

Figure G.3. 200 MW wind installed.

Figure G.4. 300 MW wind installed.
APPENDIX H

ECONOMIC DISPATCH (CASE 4)

Figure H.1. No wind.

Figure H.2. 100 MW wind installed.

Figure H.3. 200 MW wind installed.

Figure H.4. 300 MW wind installed.
APPENDIX I

MARGINAL PRICES (CASE 4)

Figure I.1. No wind.

Figure I.2. 100 MW wind installed.

Figure I.3. 200 MW wind installed.

Figure I.4. 300 MW wind installed.
APPENDIX J

ECONOMIC DISPATCH (CASE 5)

Figure J.1. No wind.

Figure J.2. 100 MW wind installed.

Figure J.3. 200 MW wind installed.

Figure J.4. 300 MW wind installed.
APPENDIX K

MARGINAL PRICES (CASE 5)

Figure K.1. No wind.

Figure K.2. 100 MW wind installed.

Figure K.3. 200 MW wind installed.

Figure K.4. 300 MW wind installed.
APPENDIX L

ECONOMIC DISPATCH (CASE 6)

Figure L.1. No wind.

Figure L.2. 100 MW wind installed.

Figure L.3. 200 MW wind installed.

Figure L.4. 300 MW wind installed.
APPENDIX M

MARGINAL PRICES (CASE 6)

Figure M.1. No wind.

Figure M.2. 100 MW wind installed.

Figure M.3. 200 MW wind installed.

Figure M.4. 300 MW wind installed.
APPENDIX N

ECONOMIC DISPATCH (CASE 7)

Figure N.1. No solar.

Figure N.2. 100 MW solar installed.

Figure N.3. 200 MW solar installed.

Figure N.4. 300 MW solar installed.
APPENDIX O

MARGINAL PRICES (CASE 7)

Figure O.1. No solar.

Figure O.2. 100 MW solar installed.

Figure O.3. 200 MW solar installed.

Figure O.4. 300 MW solar installed.
APPENDIX P

ECONOMIC DISPATCH (CASE 8)

Figure P.1. No solar.  
Figure P.2. 100 MW solar installed.  
Figure P.3. 200 MW solar installed.  
Figure P.4. 300 MW solar installed.
APPENDIX Q

MARGINAL PRICES (CASE 8)

Figure Q.1. No solar.
Figure Q.2. 100 MW solar installed.
Figure Q.3. 200 MW solar installed.
Figure Q.4. 300 MW solar installed.
APPENDIX R

ECONOMIC DISPATCH (CASE 11)

Figure R.1. No wind.

Figure R.2. 100 MW wind installed.

Figure R.3. 200 MW wind installed.

Figure R.4. 300 MW wind installed.
APPENDIX S

MARGINAL PRICES (CASE 11)

Figure S.1. No wind.

Figure S.2. 100 MW wind installed.

Figure S.3. 200 MW wind installed.

Figure S.4. 300 MW wind installed.
APPENDIX T

LOCATIONAL MARGINAL PRICE

0 MW wind
100 MW wind installed
200 MW wind installed
300 MW wind installed

Figure T.1. Case 1.

Figure T.2. Case 2.

Figure T.3. Case 3.

Figure T.4. Case 4.
APPENDIX T (continued)

Figure T.5. Case 5.

Figure T.6. Case 6.

Figure T.7. Case 7.

Figure T.8. Case 8.
Figure T.9. Case 11.
APPENDIX U

CHANGE OF DISPATCH OF COAL-FIRED GENERATORS

- 0 MW wind
- 100 MW wind installed
- 200 MW wind installed
- 300 MW wind installed

Figure U.1. Case 1.

Figure U.2. Case 2.

Figure U.3. Case 3.

Figure U.4. Case 4.
Figure U.5. Case 5.

Figure U.6. Case 6.

Figure U.7. Case 7.

Figure U.8. Case 8.
Figure U.9. Case 11.
APPENDIX V

CHANGE OF DISPATCH OF GAS-FIRED GENERATORS

Figure V.1. Case 1.                                                     Figure V.2. Case 2.

Figure V.3. Case 3.                                          Figure V.4. Case 4.
APPENDIX V (continued)

- 0 MW wind/solar
- 100 MW wind/solar installed
- 200 MW wind/solar installed
- 300 MW wind/solar installed

Figure V.5. Case 5.

Figure V.6. Case 6.

Figure V.7. Case 7.

Figure V.8. Case 8.
APPENDIX V (continued)

Figure V.9. Case 11.