THE ECONOMIC VALUE OF RELIABILITY IN DEREGULATED ELECTRICITY MARKETS

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The goal of this dissertation is to present an analytical framework for determining the economic value of both operating reliability and system adequacy in a mutually consistent manner. This is made possible using a new stochastic form of Security Constrained Optimal Power Flow, the Cornell SuperOPF, that determines the amount of generating capacity needed for reliability endogenously. The first application shows how the SuperOPF can be used to evaluate System Adequacy when wind capacity is added to a network. Although many studies focus exclusively on how wind generation lowers operating costs, this analysis also considers the capital costs of maintaining Financial Adequacy and includes the "missing money" that is generally paid through a Capacity Market. The results show why the net benefits from making an investment in wind capacity and/or upgrading a tie line are very sensitive to 1) how well the variability of wind generation is accommodated on the network by storage, and 2) how the amount of money required to maintain the Financial Adequacy of conventional generators is determined.

A second application uses the SuperOPF to determine the economic value of individual transmission lines, and how this value changes when wind capacity is added to a network. A conventional economist's view of transmission lines is that their purpose is to transfer real power from inexpensive sources to expensive sinks. This concept works reasonably well when the topology of a network is radial, but not when it is meshed. The redundancy in a meshed network is important for maintaining reliability and the analysis shows why the conventional method of valuing a transmission upgrade as the change in congestion revenue (the line flow times the nodal price difference) is misleading. The analysis distinguishes between congestion revenues for 1) transferring energy, and 2) maintaining reliability, and also determines the capital cost of the generating capacity needed for reliability when wind capacity is added. Using storage to mitigate wind variability is shown to be an effective alternative to upgrading a tie line.

BIOGRAPHICAL SKETCH

Surin Maneevitjit was born and grew up in Chiang Mai, Thailand. He graduated from Chiang Mai University in 2000, where he earned a Bachelor's degree in Computer Engineering. He entered Cornell University at USA in 2001, receiving a Master of Engineering in Electrical and Computer Engineering in 2002. Upon completion of his Master degree in engineering, he decided to refine his knowledge and research skills in a more applied field. He continued Cornell graduate program at the Department of Applied Economics and Management in August 2002. Later on, he was admitted to pursue his Ph.D in the field of Regional Science. He began research assistant work for Professor Timothy Mount in 2003 on a project testing markets for Electricity, Reserves and VArs using Power Web. Through this project, he became fascinated and got interested by this market and started to focus on the topic of reliability in deregulated electricity markets.

To My Family

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CHAPTER 1

INTRODUCTION

The two basic criteria used by the North-American Electric Reliability Corporation (NERC) to measure reliability are 1) “Adequacy” (to ensure that the installed capacity of the supply system is sufficient to meet projected future loads and limit the Loss of Load Expectation (LOLE) to one day in ten years), and 2) “Operating Reliability” (to commit generating units with sufficient reserve capacity to withstand sudden disturbances such as equipment failures). Assuming that the transmission system meets the adequacy criterion, adopting a specific Loss of Load Expectation (LOLE) standard makes it feasible to determine the corresponding reserve margins for generating capacity that are needed to maintain operating reliability in real time. However, there is no established method for measuring the economic value of reliability, and, as a result, regulators have adopted various proxy measures for meeting reliability standards, such as specifying a required level of reserve generating capacity in a region. Although it is convenient to adopt such proxy procedures, doing so obscures the underlying reasons for requiring a specific level of reliability, and more importantly, it is then virtually impossible to determine the true economic benefits of making additional investments in the system that improve reliability.

The goal of this dissertation is to present an analytical framework to determine the economic value of both operating reliability and system adequacy in a mutually consistent way. In the next chapter, general characteristics of how this framework can be used to achieve this goal are presented. Important features of the framework are 1) contingencies are considered explicitly in the optimization, 2) load shedding at a high Value-of-Lost-Load (VOLL) is allowed in all contingencies, and 3) optimization incorporates the nonlinear constraints of a full AC network. These three features make it possible to 1) determine correct shadow prices for different components of the network under different operating conditions, 2) calculate the correct net social benefit of maintaining Operating Reliability, and 3) evaluate the net economic benefit of relying more on intermittent sources of generation, such as wind capacity, that lower production costs but increase the costs of ancillary services needed to maintain reliability. By comparison, in the actual dispatch of the bulk power grid, system operators typically determine an "optimal" dispatch for an intact system and comply with operating reliability indirectly by adding physical proxy constraints, such as setting fixed minimum levels of locational reserve generating capacity, and/or specifying "proxy limits" on real power flows allowed on specific transmission lines. Corresponding nodal prices are highly misleading, particularly when a system is stressed, but these are precisely the prices that must be determined correctly to measure the economic value of reliability. In particular, the benefit of some equipment is only realized when contingencies occur.

Chapter 3 examines case studies to illustrate how this analytical framework can be extended to evaluate system adequacy when adding wind capacity to a network. Many studies in the electricity market only focus on lower operating costs in a wholesale market when adding wind capacity. However, costs of maintaining System Adequacy include the "additional money" to cover all capital costs that is generally paid through some form of Capacity Market. Hence, simply focusing on lower operating costs in a wholesale market is inadequate. An important feature of this framework is that the amount of conventional generating capacity needed to maintain Operating Reliability is determined endogenously. As a result, it is possible to determine the net social benefits of relying more on intermittent sources of generation, such as wind capacity, that lower operating costs but increases costs of maintaining System Adequacy. The capabilities of the presented framework provide a consistent economic framework for evaluating Operating Reliability in real-time markets and System Adequacy for planning purposes. Financially viable investment requires that reductions in total annual costs of the existing system should be larger than the annualized costs of financing the addition of, for example, wind generation to a network. The scenarios considered make it possible to determine 1) the amount of conventional generating capacity needed to meet peak system load and maintain System Adequacy, 2) the amount of additional money needed to pay generators to maintain Financial Adequacy, 3) changes in congestion rents for transmission that are collected by the system operator, and finally, 4) total annual system costs paid by customers directly within the Wholesale Market and, indirectly, to cover all capital costs. The results show that benefits (i.e. reduction in total annual system costs) from making an investment in wind capacity and/or upgrading a tie line are very sensitive to 1) how much of the inherent variability of wind generation has to be accommodated on the network, and 2) how remaining capital costs paid to conventional generators is determined (e.g. comparing a regulated allocation and a deregulated market). For planning purposes, it is essential to consider Financial Adequacy of conventional generators as well as the wholesale prices when evaluating economic net benefits of adding wind capacity to and/or upgrading transmission for a network.

Chapter 4 presents an analytical framework for determining the economic value of individual transmission lines, and in particular, how these economic values change when adding wind capacity to a network. The conventional economists' view of transmission lines in a network is that they are there for transferring electricity from inexpensive sources to expensive sinks. This concept works reasonably well when the topology of a network is radial, like the Western Interconnection, which has a major transmission corridor connecting inexpensive hydro sources in the Pacific Northwest to urban centers in California. However, when the topology of a network is meshed, like the Eastern Interconnection, this conventional representation falls apart. In a meshed network, there are multiple ways that electricity can flow from a specific source to a specific sink, and these flows do not necessarily respect market logic, because they are governed by the laws of physics. Kirckhoff's laws for current and voltage determine energy flows on every transmission line in an AC network, given injections and withdrawals of real and reactive power at every node. The redundancy of multiple pathways between sources and sinks in a meshed network is nothing new from the point of view of system operators. These redundancies are important for maintaining the reliability of supply. This implies that there is another level of complexity for economists to consider when determining costs and benefits of transmission lines. Hence, the conventional methodology for valuing transmission lines is inadequate. By using this framework, it is possible to distinguish between congestion revenues (flow of energy times nodal price difference) for 1) transferring energy and 2) maintaining reliability of a network. This analysis also determines how these costs change when 1) different levels of wind capacity and different qualities of wind capacity are installed at a remote location, and 2) changes are made to the capacities of selected transmission lines. The results show that net benefits (i.e. changes in total annual system costs, including capital costs and expected cost of Load-Not-Served) and relative magnitudes of congestion rents for transfers and reliability are very sensitive to how effectively the inherent variability of wind generation is accommodated in the network. With higher penetrations of wind generation, it becomes even more impractical to rely on changes in congestion revenues to develop an efficient investment plan for transmission that maintains reliability standards. The main conclusion is that evaluation of the contributions of transmission lines in a meshed network should consider combined benefits from 1) transferring real energy, 2) maintaining reliability standards, and 3) the "additional money" needed to ensure Financial Adequacy of the owners of both transmission and generation.

The overall conclusions of this dissertation have important implications for regulators in States with wholesale markets for power. The general form for the annual cost of supplying a customer with electricity can be written as follows:

Annual Cost = a + b x Energy + c x Capacity

where **a** is the cost of billing a customer,

b is the average wholesale price of energy,

c is the average price of capacity.

Currently, regulators can measure **a**, **b,** and **Energy** relatively well, although there is still some controversy about whether or not wholesale prices, **b**, observed in a market are really competitive. The main deficiency is in the measurement of **c** and **Capacity**. Determining the appropriate value of **c** is handicapped by uncertainty about actual Operating Costs and Capital Costs of generators, and measuring **Capacity** is also limited by the type of meter installed.

As shown in Chapters 3 and 4, amounts of conventional generating capacity needed for System Adequacy can vary substantially with different assumptions about the characteristics of wind generation. Furthermore, high levels of wind penetration on a network will tend to lower the wholesale price, **b**, and, as a result, lower earnings of conventional generating units. The price of capacity, **c**, must increase if Financial Adequacy of these generating units is to be maintained. At the present time, analysts and regulators have focused their concerns on the performance of deregulated wholesale markets. Far too little attention has been paid to determining the actual amount of additional money needed for System Adequacy. Financial Adequacy should be recognized as an important criterion for maintaining reliability of supply, and regulators should spend a lot more effort collecting information needed to measure legitimate amounts of additional money for generators and transmission owners. Once these accurate measurements are available, it will be feasible to restructure rates charged to customers to provide correct net economic benefits that reflect true system costs.

CHAPTER 2

RELIABILTY OF THE BULK POWER SYSTEM

2.1 Introduction

The overall objective of the chapter 2 is to demonstrate how the proposed analytical framework could be extended to evaluate the financial adequacy in deregulated electricity markets. Financial adequacy is not a new concept. It exists before electricity markets have been deregulated. It ensures a financial viable source for companies to cover their annual operating costs and annual capital costs. Under a regulated regime, vertically integrated companies could ensure their financial adequacy by requesting an additional source of incomes from regulators if their annual revenues fall below their annual costs. However, under deregulated markets, this is no longer the case. Regulators have left the market mechanism to determine the financial adequacy for the companies. Regulators have adopted two basic criteria (adequacy and operating reliability) used by NERC to measure reliability. However, a failure in financial adequacy will lead to failure in NERC two basic reliability criteria. In fact, regulators should create a form of reliability economic metric to measure financial adequacy and treat it as importance as system adequacy and operating reliability.

The chapter starts by discussing the evolution of reliability in the United States. Sections 2 and 3 describe current procedures used by regulators to maintain reliability, and explain why the use of proxy measures for reliability, such as reserve margins for generating capacity, obscure the true economic value of maintaining reliability. Hence, financial adequacy problem arises. Reliability is composed primarily of two concepts: supply security and resource adequacy. An excellent conceptual discussion of different dimensions of supply security can be found in (Amundsen 2006). One dimension of supply security relates to the operating reliability of a network as measured by involuntary losses of power -- non-price rationing or controlled rolling blackouts -- given existing stock of capital on the network. There is also a longer-run concept of "resource adequacy" that reflects the adequacy of investments in distribution, transmission, and generating capacity. Over time, investment in additional capacity should be made so long as its incremental benefits exceed its incremental cost. If too little investment is made, costs and prices, including costs associated with non-price rationing of demand and network collapses, will be too high. Thus, long-run concepts of supply security or resource adequacy are related to short run concepts of supply security or network reliability.

In Section 4, the co-optimization framework for determining an Optimal Power Flow (OPF) is presented and demonstrated how co-optimization can be used to determine the correct nodal prices for an optimum AC dispatch that meets standards of operating reliability. This framework uses co-optimization to minimize expected cost of meeting load with an intact system and a set of credible contingencies (equipment failures). The corresponding expected nodal prices reflect the patterns of dispatch for the intact system as well as for the contingencies. In contrast, the procedures currently used by system operators typically determine an optimum dispatch for an intact system and comply with operating reliability indirectly by adding physical proxy constraints, such as minimum levels of reserve generating capacity. An additional distortion of typical dispatching procedures is that system operators use a DC dispatch. Since the true physical constraints on transmission are increasingly caused by limits on voltage, these non-thermal constraints are approximated by specifying proxy limits on the real power flows allowed on a network. Even if the resulting DC dispatch corresponds exactly to the optimum AC dispatch, the corresponding expected nodal prices are highly misleading, particularly when the system is stressed, but these are precisely the prices that must be determined correctly to measure the economic benefits of reliability. Getting the prices right is the main contribution of co-optimization.

The co-optimization criterion is consistent with current practices for maintaining a standard of Operating Reliability. By allowing for involuntary load shedding to occur at a specified Value of Lost Load (VOLL), it is also possible to determine how components of the network contribute to maintaining reliability. In simple terms, if the system load is increased incrementally, eventually some load shedding will be required to obtain feasible solutions. Usually load shedding occurs first in specific contingencies such as the failure of an important generating unit. When this happens, the standard for Operating Reliability is, effectively, violated. It is then possible to determine where and how much additional capacity is needed on the network to avoid load shedding, and, in this way, address the planning problem of maintaining System Adequacy. An important implication of this is that the co-optimization framework makes it feasible to determine the economic value of both operating reliability and system adequacy in a mutually consistent way.

2.2. The Evolution of Reliability in the U.S.

After the 1965 blackout in the Northeastern United States, the electric industry made strenuous efforts to interconnect neighboring utilities so as to increase reliability by allowing neighbors to call on one another for power in the event of problems. On June 1, 1968, the North-American Electric Reliability Corporation (NERC) was set up to facilitate these interchanges by establishing technical operating standards followed (voluntarily) by the entire electric industry. The NERC consists of ten regional reliability councils that set out and monitor guidelines for the industry to follow. Figure 2.1 shows NERC Regions[1]. Before the formation of the NERC, the electricity industry simply followed (a) criteria and guides for reliable operations developed by the North American Power Systems Interconnection Committee (NAPSIC), a utility organization; and (b) reliability planning guides, in some regions. In 1980, the NAPSCI became part of the NERC and NAPSCI operations criteria and guides were adopted. After that, in 1992, the NERC board of trustees stated for the first time that adherence to NERC and regional reliability policies, criteria, and guides should be mandatory to ensure reliability. However, the NERC still had no authority to enforce compliance with policies, criteria, or guides (Hunt 2002). Later, in 1997, the NERC began working on converting its planning guides to planning standards.

[1] ERCOT - Electric Reliability Council of Texas, FRCC - Florida Reliability Coordinating Council, MRO - Midwest Reliability Organization, NPCC - Northeast Power Coordinating Council, RFC - Reliability First Corporation, SERC - Southeastern Electric Reliability Council, SPP - Southwest Power Pool, WECC - Western Electricity Coordinating Council.

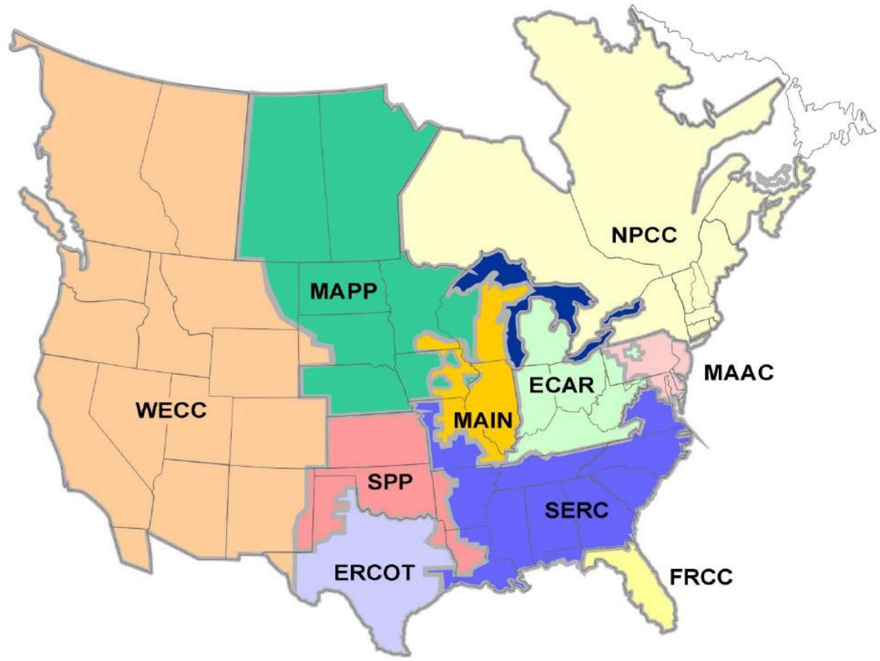

Figure 2.1: North American Electric Reliability Corporation (NERC) Regions (Administration 2010)

Another blackout occurred in the North America on August 14, 2003. It was the worst blackout ever in the United States; 50 million people lost power in the northeastern and midwestern U.S. and Ontario, Canada. The final report of the U.S.-Canada Power System Outage Task Force on the 2003 blackout concluded that the single most important recommendation for preventing future blackouts and reducing the scope of those that occur, was for the U.S. government to make reliability standards mandatory and enforceable. A year later, the NERC translated its operating policies, planning standards, and compliance requirements into an integrated and comprehensive set of 90 measurable standards called "Version 0 Reliability Standards." One year later, the U.S. Energy Policy Act of 2005 authorized the creation of a self-regulatory "electric reliability organization" that would span North America, with Federal Energy Regulatory Commission (FERC) oversight in the U.S. This legislation stated that compliance with reliability standards would be mandatory and enforceable. On July 20, 2006, the FERC certified the NERC as the "electric reliability organization" for the United States. On March 15, 2007, the FERC approved 83 NERC Reliability Standards, the first set of legally enforceable standards for the U.S. bulk power system. A few months later, on June 18, 2007, compliance with approved NERC Reliability Standards became mandatory and enforceable throughout the United States. State regulators are responsible for implementing the NERC's reliability standards. Although it is still too early to know how well these arrangements will work, it is clear that the threat of paying penalties will be a tangible incentive for state regulators to ensure that reliability standards are met. Table 2.1 summarizes the history timeline of the NERC.

Table 2.1 history timeline for the NERC (Corporation 2010)

1962-1963	The electricity industry created an informal, voluntary organization of operating personnel to facilitate coordination of the bulk power system in the United States and Canada. Four interconnected transmission systems were connected to three additional systems, forming the largest electricity grid in the world.
1960s	Electricity industry operations followed: (a) criteria and guides for reliable operations, developed by the North American Power Systems Interconnection Committee (NAPSIC), a utility organization; and (b) reliability planning guides, in some regions.
November 9, 1965	The largest blackout to this date in history occurred, as 30 million people lost power in the northeastern United States and southeastern Ontario, Canada. New York City and Toronto were among the affected cities. Some customers were without power for 13 hours.
1967	Legislation (U.S. Electric Power Reliability Act of 1967) was proposed for the creation of a council on power coordination. Although not enacted, this proposed legislation stimulated the development of an industry reliability council.
1967-1968	The Federal Power Commission (predecessor of the Federal Energy Regulatory Commission) recommended the formation of a council on power coordination made up of representatives from each of the nation's regional coordinating organizations, to exchange and disseminate information, and to review, discuss and assist in resolving matters of interregional coordination.
June 1, 1968	The National Electric Reliability Council (NERC) was established by the electric utility industry, in response to the 1965 blackout. Nine regional reliability organizations were formalized under NERC. Also formalized were regional planning coordination guides, which NERC maintained. NAPSIC operations criteria and guides continued to be maintained and practiced voluntarily.
1975	The NERC was incorporated as a non-profit corporation in New Jersey.
July 13-14, 1977	A blackout occurred in New York City. This led to the first, limited reliability provision in federal legislation. This legislation enabled the federal government to propose voluntary standards, an authority never exercised.
1980	The NAPSIC became part of the NERC, bringing reliability roles of operations and planning together in one organization. The NERC adopted NAPSIC operations criteria and guides.
1981	The NERC changed its name to the North American Electric Reliability Council in recognition of Canada's participation.

Table 2.1(Continued)

1987	The NERC updated its operations criteria and guides, renamed them “operating policies,” and added requirement statements (“shall do this”) and guideline statements (“should do this”).
1987	The NERC formed a committee to address terrorism and sabotage of the electrical supply system, at the urging of the U.S. National Security Council and Department of Energy.
1992	The NERC Board of Trustees stated for the first time that adherence to NERC and regional reliability policies, criteria and guides should be mandatory to ensure reliability, in one of six agreements-in-principle adopted by the board. (The NERC still had no authority to enforce compliance with its policies, criteria and guides.)
1993	Building on the agreements-in-principle, the NERC published "NERC 2000," a four-part action plan for the future, which recommended mandatory compliance with NERC policies, criteria and guides, and a process for addressing violations. NERC 2000 encompassed policies for interconnected systems operation, planning reliable bulk electric systems, membership recommendations, and dispute resolution.
1995	The NERC led in addressing the planning and operating reliability aspects of the FERC’s Notice of Proposed Rulemaking for a more competitive wholesale electric power market.
1996	Two major blackouts in the western United States prompted some Western Systems Coordinating Council members to enter into agreements to pay fines if they violated certain reliability standards. (the WSCC, a regional reliability organization, is now the Western Electricity Coordinating Council).
1997	The Electric System Reliability Task Force established by the U.S. Department of Energy, and an independent “blue ribbon” panel formed by NERC, both determined that grid reliability rules must be mandatory and enforceable in an increasingly competitive marketplace. Both groups recommended the creation of an independent, self-regulatory, electrical reliability organization to develop and enforce reliability standards throughout North America. Both groups concluded that federal legislation in the United States was necessary to accomplish this.
1997	The NERC set out to implement the blue-ribbon panel’s recommendation of a self-regulatory reliability organization. The NERC began working to convert its planning guides to planning standards.
1998	The NERC led the effort to assess the electric industry’s readiness for Y2K, at the request of the U.S. Department of Energy.

Table 2.1(Continued)

1999	Nine independent directors were added to the NERC Board, joining the president and 37 industry stakeholder interests, in anticipation of NERC becoming a self-regulatory organization.
2000	The NERC was appointed as the electric utility industry's primary point of contact with the U.S. government for national security and critical infrastructure protection issues.
2001	NERC governance changed. The board was replaced with a 10-member independent board, the Stakeholders Committee (now called the Member Representative Committee.)
May 1, 2002	NERC operating policies and planning standards became mandatory and enforceable in Ontario.
August 14, 2003	North America experienced its worst blackout ever, as 50 million people lost power in the northeastern and midwestern U.S. and Ontario, Canada.
April 5, 2004	The final report of the U.S.-Canada Power System Outage Task Force on the 2003 blackout concluded that the single most important recommendation for preventing future blackouts, and reducing the scope of those that occur, is for the U.S. government to make reliability standards mandatory and enforceable.
Summer 2004	The Bilateral Electric Reliability Oversight Group (BEROG) was established as a forum for identifying and resolving reliability issues in an international, government-to-government context. The BEROG grew out of the U.S.-Canada Power System Outage Task Force.
November 12, 2004	The NERC translated its operating policies, planning standards and compliance requirements into an integrated and comprehensive set of 90 measurable standards called "Version 0 Reliability Standards."
February 8, 2005	The NERC Board of Trustees adopted the Version 0 standards. Stakeholders overwhelmingly supported the standards.
April 1, 2005	Version 0 Reliability Standards were made effective. Voluntary compliance was expected as a matter of good utility practice.
August 8, 2005	The U.S. Energy Policy Act of 2005 authorized the creation of a self-regulatory "electric reliability organization" that would span North America, with FERC oversight in the U.S. This legislation stated that compliance with reliability standards would be mandatory and enforceable.

Table 2.1 (Continued)

April 4, 2006	The NERC filed an application with the FERC to become the "electric reliability organization" in the United States. The NERC filed 102 reliability standards with the FERC – the 90 Version 0 standards, plus 12 additional standards developed in the interim. The NERC filed the same information with the Canadian provincial authorities in Alberta, British Columbia, Manitoba, New Brunswick, Nova Scotia, Ontario, Quebec, and Saskatchewan, and with the National Energy Board of Canada, for recognition as the "electric reliability organization" in Canada.
July 20, 2006	The FERC certified there NERC as the "electric reliability organization" for the United States.
September-December 2006	The NERC signed Memorandums of Understanding with Ontario, Quebec, Nova Scotia, and the National Energy Board of Canada.
January 1, 2007	The North American Electric Reliability Council became the North American Electric Reliability Corporation. The new entity has a large membership base representing a cross-section of the industry.
March 15, 2007	The FERC approved 83 NERC Reliability Standards, the first set of legally enforceable standards for the U.S. bulk power system, effective June 4, 2007. The FERC stated that voluntary compliance with NERC's additional standards should continue as good utility practice.
April 19, 2007	The FERC approved eight delegation agreements by which the NERC will delegate its authority to monitor and enforce compliance with NERC Reliability Standards in the United States to eight Regional Entities, with the NERC continuing in an oversight role.
June 18, 2007	Compliance with approved NERC Reliability Standards became mandatory and enforceable in the United States.

As stated above, the evolutionary process of the setting reliability standards in US electric industry coincided with the transition from a regulated industry with vertically integrated utilities to a competitive market for electricity through liberalization and deregulation. The reliability rules and the role of the regional reliability councils and NERC were largely left in place and unchanged as liberalization of wholesale and retail markets proceeded forward in the mid-1990s. Little thought was given to whether or how these rules should change as liberalization proceeded, nor was much attention given to the interaction between evolving wholesale market mechanisms and traditional reliability rules. Most economic research on competitive wholesale markets ignored traditional reliability considerations, whether or not they were consistent with assumptions underlying wholesale markets, or how reliability and market behavior and performance could be integrated constructively. Little progress on these fronts has been made to date.

These institutional, legacy investment and political realities have significantly complicated the successful liberalization of the U.S. electricity sector. Implementing effective, i.e. no longer voluntary, reliability enforcement has proven to be especially challenging. As a result, while wholesale and retail market reforms have moved forward at different speeds across the country, incentives for some entities in the electric utility industry to maintain reliability of supply have deteriorated. For example, transmission congestion and public opposition to needed transmission investment have been a growing problem. Transmission Line Relief actions (TLRs) [2] in the Eastern Interconnection have grown by a factor of 5 since 1998. Congestion charges in PJM have grown by a factor of 10 since 1998, and congestion charges in the New York ISO have more than doubled since 2001 (Li and Tesfatsion 2010). At the same time, investment in new transmission capacity has lagged behind growth in electricity demand, and growth in new generating capacity (Hirst 2004). Policymakers are increasingly concerned about reliability problems, and reliability considerations are playing an increasingly important role at the interface of wholesale market design, transmission pricing, and transmission investment policies (Joskow 2005).

[2] Some merchant transactions are stopped by system operators when reliability is threatened.

2.3. Current Reliability Standards

Federal legislators formally recognized the importance of maintaining operating reliability in the Energy Policy Act of 2005 (EPACT05), and the major effect of this legislation has been to give the FERC the overall authority to enforce reliability standards throughout the Eastern and Western Inter-Connections (FERC 2005). The NERC has been appointed by the FERC as the new Electric Reliability Organization (ERO), and the NERC has been given the responsibility to specify explicit standards for reliability. State regulators are responsible for implementing the NERC's reliability standards. Although it is still too early to know how well these arrangements will work, it is clear that the threat of paying penalties will be a tangible incentive for state regulators to ensure that reliability standards are met.

In an electrical supply system, performance of the transmission network and level of reliability are shared by all users of the network. Reliability has the characteristics of a "public" good (all customers benefit from the level of reliability without "consuming" it). In contrast, real electrical energy is a "private" good because the real energy used by one customer is no longer available to other customers. Markets can work well for private goods but tend to undersupply public goods, like reliability (and over-supply public "bads" like pollution). The reason for this is that customers are generally unwilling to pay their fair share for a public good because it is possible to rely on others to provide it (i.e. they are "free riders"). Some form of regulatory intervention is needed to make a market for a public good or a public bad socially efficient.

If a public good or a public bad has a simple quantitative measure that can be assigned to individual entities in a market, it is feasible to internalize the benefit or the cost in a modified market. For example, emissions of sulfur and nitrogen oxides from a fossil fuel generator can be measured. Requiring every generator to purchase emission allowances for quantities emitted makes pollution another production cost. Regulators determine a cap on the total number of allowances issued in a region, and this cap effectively limits the level of pollution. Independent (decentralized) decisions by individual generators in the market determine the pattern of emissions and types of control mechanisms that are economically efficient. For example, the choice between purchasing low sulfur coal and installing a scrubber is left to market forces in a "cap-and-trade" market for emissions of sulfur dioxide.

Unfortunately, when dealing with the reliability of an electric supply system, it is impractical to measure and assign reliability to individual entities within the network in the same way that emissions can be assigned to individual generators. This is particularly true for transmission lines needed to maintain supply when equipment failures occur. The NERC uses the following two concepts to evaluate the reliability of the bulk electric supply system ((NERC) 2007):

> *1. Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.*
>
> *2. Operating Reliability — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements.*

Prior to EPACT05, the NERC standard of one day in ten years for the Loss of Load Expectation (LOLE) was widely accepted by regulators as an appropriate standard for adequacy of the bulk transmission system (i.e., this does not include outages within local distribution systems caused, for example, by falling tree limbs or ice storms). Operating a system to maintain supply when contingencies occur is operating reliability. It is typically managed by a system operator using a security constrained optimal power flow. Nevertheless, it is still very difficult to allocate responsibility for maintaining a standard of this type to individual owners of generating and transmission facilities because of interdependencies existing among components of a network. This fundamental problem has not, however, stopped regulators from trying to do so.

The basic approach used by state regulators in New England, New York, and PJM is to assume that setting reserve margins for generating capacity (i.e., setting a standard for "generation adequacy") is an effective proxy for meeting the NERC reliability standard. This new proxy for reliability can now be viewed as the sum of its parts, like emissions from generators, and the task of maintaining generation adequacy can be turned over to market forces once the regulators have set a reserve margin. In New York State, regulators have gone one step further and passed the responsibility for purchasing enough generating capacity to meet the adequacy standard on to Load Serving Entities (LSE). Regulators decide what the amount of installed capacity should be in a region, and responsibility for acquiring this amount is prorated among LSEs. An LSE that fails to comply is fined (NYISO April 2008). In contrast, ISOs in New England and PJM take responsibility for purchasing capacity needed in advance, and costs are eventually prorated to LSEs, using the actual load served in real time. This procedure identifies potential shortfalls of capacity in advance much more effectively than the NYISO procedure since it requires a commitment three years in the future planning.

Even if capacity markets are successful in maintaining generation adequacy, there are still important economic issues that are obscured when generation adequacy is used as a proxy for reliability. Changing a public good like reliability into a private good like installed capacity is a convenient approximation, because using market forces to maintain reliability standards then appears to be feasible. Nevertheless, this is not strictly correct because there is an implicit assumption that the transmission network is already adequate before decisions about generation adequacy are considered. It would be much more valuable for planning purposes to have a method of analysis that calculates net-social benefits of generation and transmission assets in terms of both delivery of real power to customers and maintenance of reliability standards. This is particularly important for evaluating the role of renewables on a network, because these sources are typically intermittent and require additional reserve capacity (or storage capacity) to maintain reliability. Before presenting the new analytical framework in the next section, some practical implications of adding an unreliable source of electricity are discussed.

The established reliability standard proposed by NERC is meant to limit failures to less than 1 day in 10 years. Is this standard too stringent, and therefore, more expensive to enforce than it should be? The answer is almost certainly no. The reason for this is that the VOLL when an unscheduled outage occurs is very high, particularly for large urban centers. A survey report published by the Lawrence Berkeley National Laboratory (LBNL) in 2004 (LaCommare and Eto 2004 Sep 01) concludes that the total cost of interruptions in electricity supply is $80 billion/year for the nation, and 72% of this total is borne by the commercial sector (with 26% for the industrial sector and only 2% for the residential sector). Frequency of interruptions is found to be an important determinant of cost because cost increases less than proportionally with length of an interruption. Costs of even relatively short interruptions of only a few minutes are substantial.

Cost estimates in the LBNL report are developed from an earlier report prepared for the Office of Electric Transmission and Distribution in the U.S. Department of Energy (Lawton, Sullivan et al. 2004) that summarizes a number of different surveys of outage costs for individual customers. For large commercial and industrial customers in different economic sectors, average costs are reported for 1-hour outages in \$/Peak kW. These average costs range from negligible, for construction, to \$168,000/MWh for finance, insurance and real estate, and the average cost for all sectors is \$20,000/MWh. Although there is a lot of variability in reported costs for an unscheduled outage, the overall conclusion is that the VOLL is very high for urban centers. The current NERC reliability standard of 1 day in 10 years corresponds to a VOLL of \$36,762/MWh (95 + 80,000/2.4, based on an operating cost of \$95/MWh, and an annual capital cost of \$80,000/MW for a peaking unit). Although this value is above the average value, it is still at the low end of the range of VOLL in the DOE report, because the distribution of values is skewed to the right.

The key to deriving the economic value of maintaining a given reliability standard is to consider the benefits of avoiding unscheduled outages. In the empirical simulations discussed later in this dissertation, a VOLL of \$10,000/MWh is used. Consequently, reducing the probability of an unscheduled outage by 0.1%, for example, still saves \$10/MWh. The analytical framework presented in section 4 treats equipment failures (contingencies) explicitly. Some components of a network may only have a positive economic value when contingencies occur, because they reduce the amount of Load-Not-Served (LNS). Other components, such as a new baseload unit, may reduce the cost of generation when the system is intact and have little affect on reliability. More generally, components will affect both operating costs for the intact system and reliability. For an intermittent source such as wind power, there is a fundamental tension between providing an inexpensive source of generation and making the existing network more vulnerable to outages. The solution to this predicament is to add new capabilities to the network that can compensate for the intermittent nature of wind power, such as controllable load response and storage capacity. Evaluating net-benefits of a portfolio of assets is one of many problems that can be evaluated using the new proposed analytical framework. Before discussing how this framework helps to measure the economic value of reliability, the next section examines how an Independent System Operator (ISO) implements current reliability standards set by NERC.

2.4. Current Reliability Practices

In a typical restructured market operated by an Independent System Operator (ISO), such as that of the New York Control Area, standards of Operating Reliability are met by requiring that minimum amounts of operating reserves are available in different regions at different times. These reserve requirements are the proxy measures of reliability discussed in the previous section. The generators submit price/quantity offers to sell energy and reserves into an auction, and the objective of the ISO is to determine the optimal patterns of generation and reserves by minimizing total costs (combined costs of energy and reserves) of meeting a forecasted pattern of load subject to network and system constraints and the specified amounts of reserves. The Last Accepted Offer is used to clear the market and set uniform market prices for energy and reserves. Market prices are adjusted for congestion and losses to determine nodal prices for energy (i.e. Locational Based Marginal Prices (LBMP)). In addition, the auction determines regional prices for reserves in a similar way.

Given the large number of nodes (over 400 in the New York Control Area) and the complexity of the network, it is computationally impractical to use a full AC representation of network flows to determine the OPF for a system of this size. As a result, a modified version of a DC OPF is used by the NYISO. For example, if the real flows on a transmission line are limited by a voltage constraint on a regular basis, the rated thermal capacity of the line is reduced in the dispatch to approximate this voltage constraint (an AC representation of network flows determines both real and reactive flows, but a DC representation determines only real flows). Hence, the lower thermal constraint on a transmission line is really another form of proxy limit that provides additional distortion in determining the true shadow prices of transmission constraints. These distortions of nodal prices are similar, in effect, to specifying minimum quantities of reserve capacity as proxies for reliability.

2.4.1. Fixed Reserve Requirements

To illustrate specific differences between using co-optimization in an OPF and using traditional fixed reserve requirements, it is convenient to start with the structure of an AC OPF using fixed reserve requirements. The objective criterion is to minimize the combined cost of energy, G_i, and reserves, R_i, needed to meet the forecasted pattern of load as follows:

$$\min_{G_i,\, R_i} \quad \sum_{\mathrm{i}=1}^{\mathrm{I}} [\, \mathrm{C}_{\mathrm{G}_\mathrm{i}}(G_i) + \mathrm{C}_{\mathrm{R}_\mathrm{i}}(R_i)] \tag{1}$$

subject to:

nodal power balancing constraints

$$F_j(\theta, V, G, Q) = 0 \quad \text{for } j = 1, \cdots, J \tag{2}$$

line power flow constraints

$$|S_l| \le S_l^{\max} \quad \text{for } l = 1, \cdots, L \tag{3}$$

voltage limits

$$V_j^{\min} \le V_j \le V_j^{\max} \text{ for } j = 1, \cdots, J \tag{4}$$

real power limits

$$G_i^{\min} \le G_i \le G_i^{\max} \text{ for } i = 1, \cdots, I \tag{5}$$

reactive power limits

$$Q_i^{\min} \le Q_i \le Q_i^{\max} \text{ for } i = 1, \cdots, I \tag{6}$$

spinning reserve ramping limits

$$0 \le R_i \le R_i^{\max} \text{ for } i = 1, \cdots, I \tag{7}$$

unit capacity limits

$$G_i + R_i \le G_i^{\max} \text{ for } i = 1, \cdots, I \tag{8}$$

Fixed Reserve Requirement for all N regions

$$\sum_{n=1}^{N} \sum_{i \in k} R_{ni} \ge \alpha \tag{9}$$

and **Fixed Reserve Requirements** for N* < N regions

$$\sum_{i \in n} R_{ni} \ge \alpha_n \text{ for } n = 1, \cdots, N^* \tag{10}$$

where i: generator index ($i = 1, 2, \cdots, I$)

j: bus index ($j = 1, 2, \cdots, J$)

l: transmission line index ($l = 1, 2, \cdots, L$)

n: regions ($n = 1, 2, \cdots, N$)

G_i / Q_i: real/reactive power output of generator i.

R_i: spinning reserve carried by generator i.

θ_j: voltage angle of bus j.

V_j: voltage magnitude of bus j.

S_l: power flow of line l.

$G_i^{\min}, G_i^{\max}$: minimum and maximum real energy for generator i.

$Q_i^{\min}, Q_i^{\max}$: minimum and maximum reactive power for generator i.

$R_i^{\max}$: maximum reserve for generator i.

$V_j^{\min}, V_j^{\max}$: voltage magnitude limits for bus j.

$S_l^{\max}$: power flow limit for line l.

$C_{G_i}(G_i)$: energy cost for operating generator i at output level G_{ik}.

$C_{R_i}(R_i)$: reserve cost for generator i carrying R_{ik} spinning reserve.

Equations (1) to (8) represent a standard OPF for an AC network, and (9) and (10) represent mandated levels of reserve capacity needed in different regions to cover unscheduled failure of equipment. In practice, determining specified levels of reserves needed to meet the established standard of Operating Reliability depends on prior analyses, but it is likely that actual mandated levels of reserve capacity are relatively conservative (i.e. high) to reduce the likelihood of facing unpleasant political consequences of a blackout.

If Generator *i* with capacity G_i*, for example, is part of the optimal dispatch for the intact system, it could have an unexpected failure. In this case, Generator *i* would be eliminated and the OPF would be solved again using only the other generating units committed in the first optimal dispatch, after lowering appropriate reserve requirements in (9) and (10) by G_i*. Hence, the actual dispatch and prices paid could be substantially different from the optimal solution for the intact system if a contingency occurs. Furthermore, there is no guarantee that an optimal solution will actually be feasible in a given contingency. The feasibility of the dispatch is dependent on having enough reserve capacity available in the right locations to cover the contingency, and in practice, mandated levels of reserves are reset relatively infrequently because characteristics of the system change relatively slowly over time.

2.5. Using the SuperOPF to Represent Reliability

(Chen, Mount et al. 2005) have proposed an alternative manner of determining optimal dispatch and nodal prices in an energy-reserve market using “co-optimization” (CO-OPT). The proposed objective function minimizes the total expected cost (combined production costs of energy and reserves) for a base case (intact system) and a specified set of credible contingencies (line-out, unit-lost, and high load) with their corresponding probabilities of occurring. Further works have been greatly expanded by (Murillo-Sanchez, Zimmerman et al.) to consider both upward and downward excursions as “reserve”, albeit of a different kind, as well as reactive reserve. This makes it easier to integrate the approach to a day ahead market-based scheduling framework in which there must be a real time follow-through (Thomas, Murillo-Sanchez et al. 2008). According to (Thomas, Murillo-Sanchez et al. 2008), the SuperOPF is a new stochastic contingency-based security constrained AC OPF formulation that tackle the following problems 1) the AC OPF problem with a full AC nonlinear network model and constraints, 2) the N-1 contingency security problem, 3) the problem of procuring an adequate and locationally relevant supply of real and reactive power and attendant reserves to meet critical contingencies, 4) the problem of setting day-ahead contract prices for energy, for reactive power, and for real and reactive reserves, 5) a consistent mechanism for re-dispatching and pricing the next day given load, supply and contingency certainties. Complete mathematics of the formulation can be found in (Murillo-Sanchez, Zimmerman et al.). A detail discussion on the SuperOPF and the implementation of the SuperOPF could be found in (Lamadrid, Maneevitjit et al. 2008). A SuperOPF software tool used in this dissertation is implemented as a part of the MATPOWER (Zimmerman, Murillo-

Sanchez et al. 2009) (Zimmerman, Murillo-Sanchez et al. 2011) OPF formulation software package.

In a nutshell, by using CO-OPT, the optimal pattern of reserves is determined endogenously and adjusts to changes in physical and market conditions of the network. For example, the amount of reserves needed typically increases after the addition of an intermittent source of generation from a wind farm. This framework corresponds to using a conventional *n*–1 contingency criterion to maintain Operating Reliability. In practice, the number of contingencies that affect the optimal dispatch is much smaller than the total number of contingencies. In other words, by covering a relatively small subset of critical contingencies, all of the remaining contingencies in the set can be covered without shedding load. In the SuperOPF, the CO-OPT criterion is modified to include the cost of Load-Not-Served (LNS), and also distinguishes between positive and negative reserves for both real and reactive power. A high VOLL is specified as the price of LNS. In the conventional Security-Constrained OPF used by most System Operators, n-1 contingencies are treated as "hard" constraints rather than as economic constraints, as they are in the SuperOPF[3]. Increasing stress on a network by, for example, increasing peak system load over a planning horizon eventually causes load shedding, and typically, load shedding occurs first in one or more of the contingencies. Since the expected cost of LNS in a contingency is determined by multiplying a large VOLL by a small probability, the overall effect on total expected system cost may be modest. From a social planner's perspective, the standard of one day in ten years for the LOLE should correspond to equating a reduction in the expected annual cost of operating the system, including changes in the expected cost of LNS, with the annual cost of making an investment in additional capacity.

[3] A hard constraint is equivalent to specifying the VOLL as plus infinity.

Using the SuperOPF, the System Operator determines the optimal dispatch for energy and reserves for the base case (intact system, k = 0) and for K different contingencies by minimizing the expected cost of meeting load in the (K + 1) states of the system as follows (additional components for reactive power and dynamic VAr are included in the SuperOPF but not shown in the objective function below):

$$\min_{G_{ik},\, R_{ik},\, LNS_{jk}} \quad \sum_{k=0}^{K} p_k \left\{ \sum_{i=1}^{I} \Big[C_{G_i}(G_{ik}) + INC_i(G_{ik} - G_{i0})^{+} + DEC_i(G_{i0} - G_{ik})^{+} \Big] \right\}$$
$$+ \sum_{k=0}^{K} p_k \sum_{j=1}^{J} VOLL_j \times LNS_{jk} + \sum_{i=1}^{I} [C_{R_i}(R_i^{+}) + C_{R_i}(R_i^{-})]$$

Subject to meeting LOAD and all nonlinear AC CONSTRAINTS of the network,

where $k = 0, 1, \ldots, K$ is a CONTINGENCY

$i = 1,2, \ldots, I$ is a GENERATOR

$j = 1,2, \ldots, J$ is a LOAD

p_k is the probability of Contingency k occurring

G_i is the quantity generated in MWh

$C_G(G_i)$ is the COST of generating G MWh

$INC(G_{ik} - G_{i0})^{+} > 0$ is the cost of increasing generation from the “base”

$DEC(G_{i0} - G_{ik})^{+} > 0$ is the cost of decreasing generation from the “base”

$VOLL_j$ is the VALUE OF LOST LOAD

LNS_{jk} is the LOAD NOT SERVED MWh

$R_i^{+} = (Max[G_{ik}] - G_{i0})^{+} < Ramp_i$ is the quantity of UP reserves in MW

$C_R(R_i^{+})$ is the COST of providing UP MW of spinning RESERVES

$R_i^{-} = (G_{i0} - Min[G_{ik}])^{+} < Ramp_i$ is the quantity of DOWN reserves in MW

$C_R(R_i^{-})$ is the COST of providing DOWN MW of spinning RESERVES

The objective function above represents a simplification of the objective function used in the SuperOPF, because the reactive components of generation, reserves, and load are not all identified explicitly, and, for the remainder of this dissertation, the discussion only refers to real power (energy) even though reactive power is, actually, included in our study[4]. It would also be straightforward to include more flexible forms of load response, such as interruptible contracts and price responsive demand, but capabilities of this type were not used for this dissertation.

The reserve capacity for each generator in contingency *k* is defined as the difference between the maximum (minimum) of the $K+1$ optimal levels of dispatch (which may be less than the true physical maximum) and the optimal level of dispatch for the intact system ($k = 0$). The maximum (minimum) dispatched capacity for every generator is realized for generating real energy in at least one contingency. The amount of reserve capacity is limited for each generator by a specified Ramp Rate. This ensures that each generator has the physical capacity to meet the optimal dispatch in all specified contingencies. The Max[G_{ik}] over the K + 1 contingencies for the system peak load determines the amount of capacity needed for System Adequacy. Adding wind capacity to a network with no mitigation of the variability of amounts generated by wind typically increases both Up and Down Reserves, and, as a result, the total amount of conventional, non-wind capacity needed for System Adequacy may actually increase. Paying the full cost of this extra capacity is potentially a major additional system cost of adding wind capacity, and, in the case study, reducing need for additional capacity is a benefit of using storage batteries to mitigate variability of wind generation.

[4] It is assumed that each generator has contracted in advance to provide VArs at no additional cost up to the limits of a specified Capability Curve, and loads are specified to have a constant power factor, implying that nodal prices cover the costs of both real and reactive power.

The objective function used in the SuperOPF implies that optimum quantities of spinning reserves for $k = 0$ are contracted and paid ahead of real time in, for example, a day-ahead market. Generators are compensated for actual energy generated using real-time prices, but the payments could be made in two parts: one paying the contracted dispatch for k = 0 using day-ahead prices, and the other paying the difference between the actual dispatch and contracted dispatch using real-time prices. In addition, extra payments for shifting generation away from the base dispatch can also be specified (the INCs and DECs), and these costs can be used to reflect inefficiencies associated with ramping generators. However, the INCs and DECs are all zero in the case studies that are presented in Chapter 3 and 4. The level of reserve capacity for any generator is determined endogenously, and responds to conditions on the network, such as the pattern of forecasted load. As a result, it is possible to determine net economic benefits of relying more on an intermittent source of generation, such as wind capacity, that lowers operating costs but increases the cost of maintaining System Adequacy.

The regulated standard of Operating Reliability is maintained if load is met in all of the contingencies. Finding optimal values of $LNS_{jk} > 0$ is equivalent to violating this reliability standard, and signals a failure of System Adequacy in a planning application, which would be corrected by increasing the system capacity in some way. Since the *VOLL* is specified to be very large compared to typical market prices, it is important to note that a major part of the total benefit of many components of the grid comes from avoiding unscheduled load shedding when contingencies occur. When the system is adequate, no failures of Operating Reliability will be observed, and, therefore, it is no longer possible to use observed market prices to determine the full net-benefit of an investment that was made to avoid unscheduled outages. These are the "events that didn't happen" that should be considered when calculating the economic value of reliability in a planning model.

One of the many useful capabilities of the SuperOPF is that optimization can be considered in two stages. The first stage is the full co-optimization, which can be viewed as the optimum way to minimize expected costs and maintain Operating Reliability when the system is adequate (i.e. all $LNS_{jk} = 0$ for all credible contingencies). This stage determines amounts and prices of energy and reserves contracted in advance of real time (e.g. one day ahead). The second stage corresponds to a real-time OPF when the actual state of the system is known and a contingency may have occurred. The objective is now to minimize the incremental cost of adjusting from the contracted amounts of resources from the first step to meet actual system conditions.

The second stage of the SuperOPF treats the actual state as the new base ($k = 0$) and includes all remaining contingencies in the same manner as before. This implies that the optimum dispatch in the second stage still attempts to maintain Operating Reliability. However, if a major failure has already occurred, it may not be possible to meet the load in all situations if a second failure occurs. This would not be a violation of the typical standard of Operating Reliability assuming that the specification of the first stage covered all credible contingencies. For example, if regulators define System Adequacy as the ability to cover all single failures, there is no guarantee that the system can cover the relatively rare event that two or more failures occur. Following any major contingency, bringing the system back into compliance with Operating Reliability would require adding resources that were rejected from the auction in the first stage of the optimization with the intact system.

Current practices adopted in restructured markets are more in line with the optimization for Fixed Reserve Requirements in (1) – (10), and the expected cost of meeting the contingencies is not explicitly part of the objective function. In the New York Control Area, for example, a modified DC OPF minimizes the expected cost of meeting load for the intact system with specified levels of reserves included. If a contingency occurs, there is an ordered list of options, such as using reserve capacity and exercising contracts for interruptible load, with shedding load as the least desirable option. Since contingencies are not considered explicitly in the optimization, it is virtually impossible to determine the true economic value of reliability based on market solutions, and meeting a given reliability standard is treated as a physical constraint rather than as an explicit economic component of the objective function, as in the SuperOPF.

After a contingency occurs, the objective in the SuperOPF is still to minimize expected cost over all contingencies, even if this requires shedding some load in some contingencies. The amount and location of load shedding is determined optimally. For example, if the VOLL in an urban region is much higher than that in other regions, the solution will implicitly give more weight to avoiding the shedding of load in the urban area. In fact, the SuperOPF is consistent with the relatively successful market design in Australia.

(Anderson, Zimmerman et al. 2010) tested the SuperOPF optimization method against the traditional Fixed Reserves requirement (reserves = fixed percentage of the system load). They compare the quantity and cost of reserves under each method for the same set of input data and scenarios. Figure 2.2 shows that the SuperOPF requires substantially less reserves and virtually no load shedding compared to traditional Fixed Reserves.

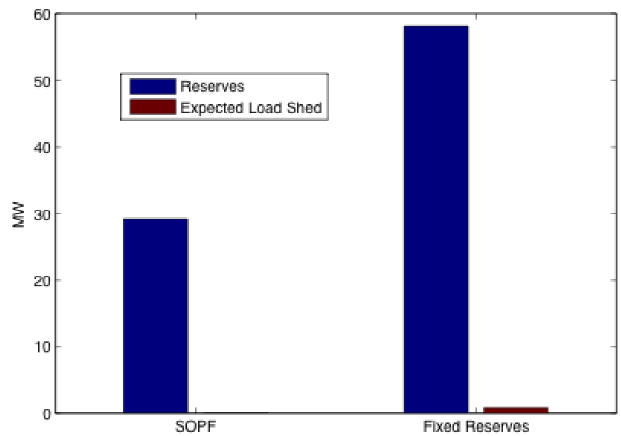

Figure 2.2: Comparison of the quantity of reserves (MW) and load shedding (MW) in the SuperOPF and in Fixed Reserves (Anderson, Zimmerman et al. 2010)

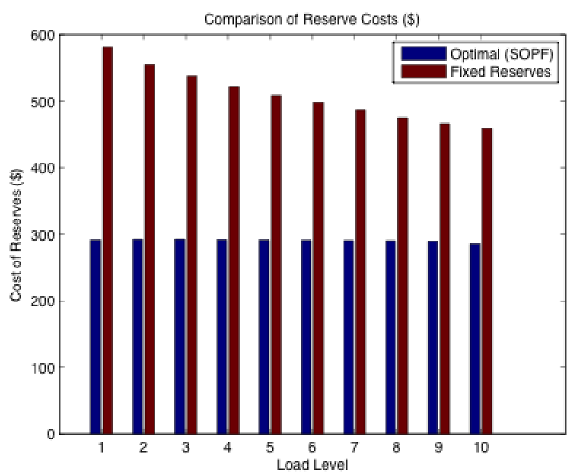

Figure 2.3: Comparison of the cost of reserves in different load levels between the SuperOPF and Fixed Reserves (Anderson, Zimmerman et al. 2010)

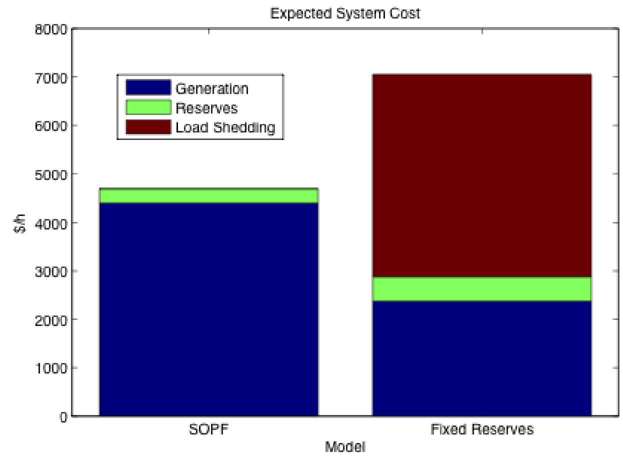

Figure 2.4: Comparison of the expected total system cost ($/h) between the SuperOPF and Fixed Reserves (Anderson, Zimmerman et al. 2010)

Figure 2.3 shows that the SuperOPF has lower operating costs because it allocates both generation and reserves optimally. The Total System Cost ($/h) that includes capital costs is also substantially smaller in the SuperOPF compared to using Fixed Reserves, as shown clearly in Figure 2.4. The comparison highlights the benefits of the optimal allocation of reserves by 1) Lower total quantity (and cost) of reserves, 2) Much less load shedding, and 3) Reduced expected cost of serving load. The results indicate that customers would benefit economically from lower electricity bills and maintain operating reliability standards if the co-optimization procedure used in the SuperOPF was adopted.

2.6. Summary and Conclusion

This chapter discusses how the regulation of reliability of the electricity supply system in the United State has evolved and presents current procedures used by regulators to maintain reliability. It also explains why the use of proxy measures for reliability, such as reserve margins for generating capacity, obscures the true economic value of maintaining reliability. Given the new energy policy that will rely more on intermittent sources of generation, such as wind capacity, it is important to have procedures for measuring the economic costs of maintaining reliability. Currently, system operators determine an "optimum" dispatch for an intact system and treat Operating Reliability as a set of physical constraints rather than as an economic cost. Hence, it is not feasible to evaluate the true economic benefits of generating units that lower production costs but increase the cost of ancillary services needed to maintain reliability. Since the SuperOPF determines the amount of conventional generating capacity needed to maintain Operating Reliability endogenously, it is possible to determine the net economic benefits of those reserve generating units. This feature provides a consistent economic framework for evaluating Operating Reliability in real-time markets and System Adequacy for planning purposes. These matters will be illustrated using case studies in Chapter 3.

(Toomey, Schulze et al. 2005) conducted an economic analysis of an electrical supply system, paying particular attention to physical constraints. The basic economic complication for his model is that it includes electrical equipment constraints such as generator limits and line flow limits, as well as network constraints, i.e., Kirchhoff's laws. Attributes contributing to reliability and quality of service are public goods, e.g. voltage, frequency, and generation reserves. Toomey's study shows that, most of the time (in an intact system), the value of transmission lines is virtually zero. However, when low probability contingencies occur, transmission lines are very valuable. In other words, congestion revenues do not provide a viable source of income for transmission lines when the system is intact. Income is realized for maintaining reliability on a network. Therefore, it is important to evaluate the economic value of transmission lines for maintaining reliability of a network. The analysis in Chapter 4 uses the SuperOPF to distinguish between congestion revenues (flow of energy times the nodal price difference) for 1) transferring energy, and 2) maintaining reliability of a network. The analysis also determines how these economic values change when 1) a different level of wind capacity and different qualities of wind capacity are at a remote location, and 2) changes are made to the capacity of selected transmission lines.

CHAPTER 3

THE ECONOMIC VALUE OF GENERATORS

3.1 Introduction

In a recent study initiated by the US Department of Energy (DOE) (DOE 2008), the effects of increasing dependence on wind energy to 20% of the total generation of electricity by 2030 are evaluated. The study provides a relatively positive view of this scenario, suggesting that the cost impact could be as low as its current level - 10% or less of the value of the wind energy generated. The DOE study focuses on the initial capital cost of installing wind capacity and upgrading the transmission network and compares these costs to the lower operating costs resulting from wind energy displacing fossil fuels. The objective of this chapter is to show that there are other costs of wind power associated with the need to maintain the "Financial Adequacy" of conventional generating capacity. Since wind capacity is essentially a non-dispatchable source of energy, it contributes relatively little capacity for meeting the reliability standard of "Generation Adequacy". Nevertheless, wind generation, when it is available, is essentially free and displaces most conventional sources of generation. As a result, capacity factors of conventional generators are typically reduced when wind capacity is added. This happens even though the total amount of conventional capacity needed to maintain reliability may actually increase. Consequently, these conditions lead to increasing amounts of "missing money" for generators. In regulatory economic literature, "missing money" is defined as the economic loss of a capital-intensive facility operating in a competitive market environment (Joskow 2007) (Peter and Steve 2006). Generally this additional money is paid through some form of Capacity Market in most deregulated markets in the US[5]. For example, generating units in New York City have, until recently, been paid over $100,000/MW/year (NYISO 2008). This analysis uses the SuperOPF, which determines the amount of conventional generating capacity needed to maintain Operating Reliability endogenously. Consequently, it is possible to determine the net social benefits of greater reliance on adding the wind capacity. This feature provides a consistent economic framework for evaluating Operating Reliability in real-time markets, and System Adequacy for planning purposes.

The case studies presented show that total system costs charged to customers may increase when a new wind farm replaces an existing coal unit on a network, even though wholesale prices are lower. With the wind farm in place, the increase in additional money is larger than the decrease in total operating costs in the Wholesale Market. For an investment to be economically viable from an economic planning perspective, the total annual system cost of meeting load and maintaining reliability must decrease, and this reduction in cost must be larger than the annualized cost of financing the investment. If some form of storage capability, such as a battery, mitigates the variability of wind generation and costs less than providing alternative generation, the total annual system cost of the existing system may decrease. The battery charges when wind speed is higher than predicted, and discharges when it is lower than predicted, and, in this way, net wind generation is smoothed over time. As a result, there is an effective floor for the amount of generation from wind capacity when indirect generation from discharging a battery is included. The presence of this floor reduces the total amount of conventional generating capacity that is needed to meet the peak system load and maintain System Adequacy, and, as a result, the

[5] Some "energy only" markets do not have a Capacity Market, and some other way of maintaining the financial viability of conventional generators, such as tolerating high, "scarcity" prices, is used.

amount of additionalmoney is also reduced. In addition, the total amount of wind that is spilled (i.e. wasted) is reduced when batteries are coupled with a wind farm[6].

This chapter demonstrates through a case study 1) why Financial Adequacy is an important concept that should be considered by system planners, 2) why the social value of storage and controllable load increases when intermittent sources of generation are added to a network, and 3) how the cost of additional money to customers differs between a regulated and a deregulated market.   The results show that benefits (i.e. reduction in total annual system costs) from making an investment in wind capacity and/or upgrading a tie line are very sensitive to 1) how the variability of wind generation is accommodated on the network, and 2) how additional money paid to conventional generators is determined (e.g. comparing a regulated allocation and a deregulated market). For planning purposes that complement the standard engineering criterion of maintaining "System Adequacy", it is essential to consider the Financial Adequacy of conventional generators as well as wholesale prices when evaluating economic net benefits of adding wind capacity to/and or upgrading transmission for a network.

The structure of this chapter includes five additional sections. Section 3.2 describes the SuperOPF and shows how this analytical framework relates to NERC standards for Operating Reliability and System Adequacy. Section 3.3 presents specifications for a case study that considers effects of replacing a coal unit with a large wind farm with three times the installed capacity of the coal unit. Since the wind farm causes more congestion on the network when the wind blows, a series of additional scenarios show the effects of upgrading the capacity of a tie line to reduce this congestion. Since congestion rents on the network are treated as one source of

[6] In one scenario, "must-take" contracts for wind generation are evaluated through making the cost of not using available wind generation high, and, in this scenario, the total annual system cost of maintaining System Adequacy is substantially higher than the corresponding cost without a wind farm.

income for transmission owners, reducing these rents implies that there will be more additional money that must be paid by customers outside the Wholesale Market to ensure that transmission owners are financially viable. Additional money for both generators and transmission owners contributes to the total annual system cost of maintaining System Adequacy and Financial Adequacy. Results for all scenarios are presented in Section 3.4, and implications of these results for amounts of additional money in a regulated and a deregulated market are discussed in Section 3.5. Overall conclusions of the analysis and some suggestions for regulators are summarized in Section 3.6.

3.2 NERC Reliability Standards and the SuperOPF

Federal legislators have formally recognized the importance of maintaining Operating Reliability in the Energy Policy Act of 2005 (EPACT05), and the major effect of this legislation is to give the FERC overall authority to enforce reliability standards throughout the Eastern and Western Inter-Connections (FERC 2005)The NERC has been appointed by the FERC as the new Electric Reliability Organization (ERO), and NERC has been given the responsibility to specify explicit standards for reliability. A draft set of reliability standards was released for public comment from April 23rd to May, 25th, 2009 (NERC 2009). This report contains over 1000 pages and covers a wide range of different topics. Although the important issue of System Adequacy is referenced many times, the report recognizes the importance of and major complications involved in how the North American Bulk Power Network is governed. There are many layers of governance, and in general, state regulators determine rules for maintaining System Adequacy.

The NERC uses the following two concepts to evaluate reliability of the bulk electric supply system: ((NERC) 2007)

1. Adequacy — The ability of the electric system to supply the aggregate electrical demand and energy requirements of customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

2. Operating Reliability — The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated failure of system elements.

To simplify the concept of Operating Reliability, it is convenient to adopt a single measure, and the traditional NERC standard of one day in ten years for the LOLE is still treated by many regulators as the appropriate measure for reliability of the bulk transmission system (i.e., this does not include outages of local distribution systems caused, for example, by falling tree limbs and ice storms). Adequacy implies that past investments in the capacity of the electric delivery system must be sufficient to make real-time operations meet reliability standards. As a result, the adequacy standard has important economic and financial implications that should be addressed by regulators in a more systematic and transparent way. It is argued that a new criterion of "Financial Adequacy" should be treated as one of the standard measures used by system planners to evaluate the desirability of proposed changes to system capacity.

(Chen, Mount et al. 2005) have proposed an alternative way to determine optimal dispatch and nodal prices in an energy-reserve market using CO-OPT. The proposed objective function minimizes the total expected cost (combined production costs of energy and reserves) for a base case (intact system) and a specified set of credible contingencies (line-out, unit-lost, and high load) with their corresponding probabilities of occurrence. Using CO-OPT, the optimal pattern of reserves is determined endogenously and adjusts to changes in physical and market conditions of the network. For example, the amount of reserves needed typically increases after the addition of an intermittent source of generation from a wind farm. This framework corresponds to using a conventional n–1 contingency criterion to maintain Operating Reliability. In practice, the number of contingencies affecting the optimal dispatch is much smaller than the total number of contingencies. In other words, if a relatively small subset of critical contingencies is covered, all remaining contingencies in the set can be covered without shedding load.

The following section describes characteristics of the 30-bus test network used in the case study and specifications for the simulations. The basic objective of this analysis is to evaluate the effects of replacing an existing coal unit with a large new wind farm. The initial amounts of installed capacity are sufficient to meet the standard for System Adequacy, and, since wind generation is inherently intermittent, the installed capacity of the wind generators is substantially larger than the capacity of the coal unit. In addition, this analysis determines the economic benefit of upgrading a transmission tie line to transfer more wind generation from a remote location to an urban center.

3.3 Scenarios Evaluated in the Case Study

The case study is based on a 30-bus test network that has been used extensively in our research to test the performance of different market designs using the *MATPOWER* platform. A one-line-diagram of this network is shown in Figure 3.1 below. The 30 nodes and 39 lines are numbered in Figure 3.1, and this numbering scheme provides the key to identifying the locations of the specific contingencies described in the following discussion. In addition, the six generators are also identified. The network is divided into three regions, Areas 1 – 3. Area 1 represents an urban load center with a large load, a high VOLL and expensive sources of local generation from Generators 1 and 2. The other two regions are rural with relatively small loads, low VOLLs and relatively inexpensive sources of generation from Generators 3 – 6. Consequently, an economically efficient dispatch uses the inexpensive generation in Areas 2 and 3 to cover the local loads and as much of the loads in Area 1 as possible.

3.3.1 The Test Network

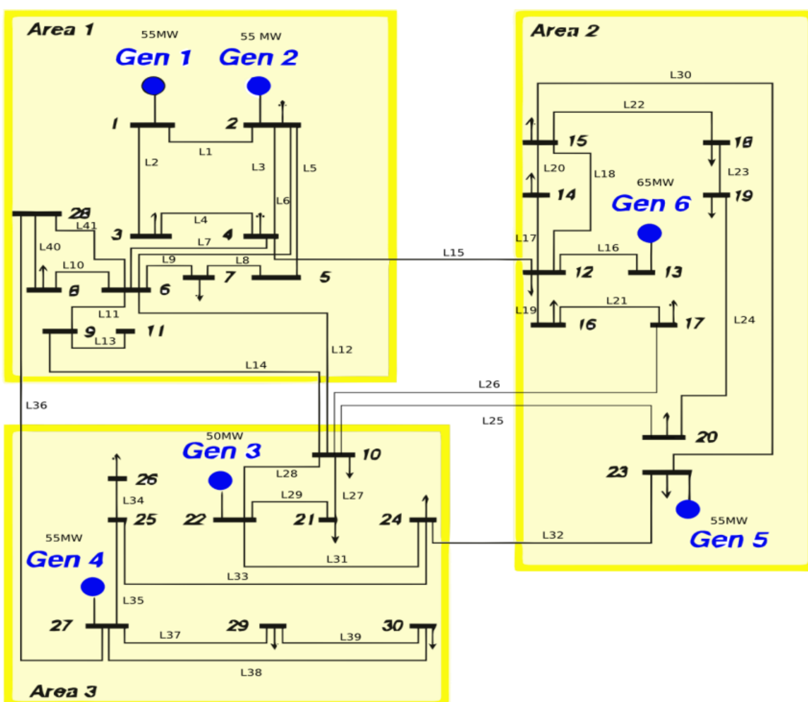

Figure 3.1: A One-Line-Diagram of the 30-Bus Test Network.

The capacities of transmission tie lines linking Areas 2 and 3 with Area 1 (Lines 12, 14, 15 and 36) are limiting factors. Since lines and generators may fail in contingencies, the generators in Area 1 are primarily needed to provide reserve capacity. The general structure of the network poses the same type of problem faced by system operators and planners in the New York Control Area. Most of the load is in New York City (i.e. Area 1) and inexpensive sources of baseload capacity (hydro, coal and nuclear) are located upstate (i.e. Areas 2 and 3) (Mount, Lamadrid et al. 2009).

3.3.2 The Realization of Wind Generation

There are three different forecasts of the level of wind generation (high, medium, and low), and each forecast has four possible outcomes, summarized for NORMAL Wind in Table 3.1. With no wind capacity installed, the contingency $k = 0$ corresponds to the intact system using the forecasted level of load (i.e. the network shown in Figure 3.1). The analysis that underlies the information presented in Table 3.1 has three components that are described in a paper by Anderson and Cardell (Anderson and Cardell 2008). The first component is a set of time-series data for hourly wind speeds at a specific location (in New England for this case study). The second component is an ARMA model for predicting wind speed (one hour ahead for this case study), and, finally, there is a power curve for a wind turbine that converts a given wind speed to the amount of energy generated (wind turbines are also specified as a potential source of positive reactive power in the SuperOPF).

Table 3.1: Specifications of Wind Contingencies for NORMAL and NICE Wind*

Forecasted Wind Speed	Probability of Forecast Occurring	Wind Generation % of Rated Installed Wind Capacity		Probability of Actual Generation
		NORMAL	NICE	
LOW (0-5meters/second)	**11%**	0%	35%	66%
		7%	35%	26%
		33%	35%	5%
		73%	38%	3%
MEDIUM (5-13meters/second)	**46%**	6%	41%	24%
		38%	55%	20%
		62%	55%	18%
		93%	58%	38%
HIGH (>13meters/second)	**43%**	0%	35%	14%
		66%	70%	4%
		94%	70%	3%
		100%	70%	79%

* Realized levels of net wind generation in Column 4 are different from levels for NORMAL (and NASTY Wind), and represent the effect of coupling batteries with the wind farm to reduce the range of outcomes for a given forecast of wind speed and to provide a floor > 0 for the amount generated.

An important point that underlying levels of generation in Column 3 of Table 3.1 is that ranges of observed wind speeds for each wind forecast (Low, Medium or High) are much larger than the ranges of forecasted wind speeds that define each bin. Consequently, ranges of generation for a given wind forecast are also very large. The outcomes for a high wind forecast are the most challenging for system operators because there is a substantial probability of 14% that the turbines will cut out at very high wind speeds (>25meters/second) to avoid damaging equipment. Hence, the distribution of wind speeds is bimodal, with modes at 0% and 100% of the maximum level of generation[7].

The following four different cases for wind generation are considered:

1) NO Wind: with a 35 MW coal unit installed at Generator 6,

2) NORMAL Wind: with the coal unit at bus 13 replaced by 105MW of wind capacity, using wind speed specifications in Table 1, and zero for the offer price in the wholesale auction,

3) NICE Wind: the same as Case 2 with a different set of specifications for realizations of wind generation (see Table 3.1) that represent the net effect of coupling wind generation with storage batteries[8],

4) NASTY Wind: the same as Case 2 with the offer price in the wholesale auction set to -$1,500/MWh to "force" the acceptance of wind generation in the auction and represent a "Must-Take" form of contract between the wind farm and the system operator.

In addition, the same four Cases are rerun after making an upgrade to Transmission Line L15 in Figure 3.1. This upgrade doubles the transfer capacity of the main tie line linking the wind farm in Area 2 to the urban center in Area 1. These Cases are referred to as Case 1UP, Case 2UP, etc.

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[7] These extreme specifications are used on purpose in this case study to provide stress on the network when wind capacity is installed. In practice, there may be a substantial amount of smoothing of total wind generation from wind farms located in different regions of a network.

[8] The rationale for Case 3 is that batteries are charged when the realized wind speed is high, and discharged when wind speed is low, and, most importantly, when wind turbines cut out for safety reasons at very high wind speeds.

3.4 Results for the Wholesale Market

Results presented in this section summarize economic costs for the network shown in Figure 3.1 for meeting the same annual pattern of load for the eight different scenarios discussed in the previous section. For this analysis, it is assumed that the wholesale market is deregulated. The main questions of interest in this section are 1) how much generating capacity is needed to maintain System Adequacy, and 2) what happens to wholesale prices and operating costs.

The four different types of wind generation considered are NO Wind, NORMAL Wind, NICE Wind (i.e. wind generation coupled with storage), and NASTY Wind (i.e. must-take contracts for wind generation), and the order of the eight scenarios is:

1. Case 1: NO Wind
2. Case 1UP: NO Wind + Upgrade
3. Case 2: NORMAL Wind
4. Case 2UP: NORMAL Wind + Upgrade
5. Case 3: NICE Wind
5. Case 3UP: NICE Wind + Upgrade
7. Case 4: NASTY Wind
8. Case 4UP: NASTY Wind + Upgrade

For each scenario, reported annual costs are sums over 100 load levels of expectations of costs for the three forecasts of wind speed shown in Table 3.1, using the second-stage optimization of the SuperOPF.[9] Key results for the eight scenarios are presented in Table 3.2. The first row (Load Paid) shows that annual payments made by customers in the wholesale market are substantially lower than those in the

[9] In other words, expected costs are computed for 18 different contingencies for each of the three forecasts of wind speed.

NO Wind scenario (Cases 1 and 2) for all wind scenarios except Case 4 (NASTY Wind). These cost reductions represent the displacement of fossil fuels by wind generation whenever the wind blows, and, at low loads, expected generation from wind is the dominant source. For NICE Wind with the upgraded tie line (Case 3UP), customers only pay one sixth of the corresponding cost with NO wind (Case 1) in the wholesale market. Wind also displaces fossil fuels in Case 4, and high wholesale prices paid by customers are caused by the increased cost of dealing with congestion on the network.[10]

Table 3.2: Summary of Key Results

	Case 1	Case 1UP	Case 2	Case 2UP	Case 3	Case 3UP	Case 4	Case 4UP
Load Paid ($1000/Year)	$68,915	$66,171	$22,373	$14,705	$23,560	$11,934	$78,570	$36,650
Gen Capacity Needed (MW)*	283	288	288	286	242	259	295	292
Max Wind Committed (MW)*	0	0	35	83	43	73	105	105
Conventional Generation (%)	100	100	88	86	78	75	56	55
Load Not Served (Hours/Year)	16	15	4	4	7	7	34	20
***105 MW of Wind Capacity replaces 35MW of Coal capacity in Cases 2,3 and 4**								

The generally lower wholesale costs of purchases with wind generation in Table 3.2 contrast with the amounts of conventional generating capacity needed for System Adequacy (Gen Capacity Needed). Capacity needed is roughly the same with

[10] When wind generation is the dominant source at low loads, it is difficult to accommodate this generation on the network because so much of the total generation is produced at a single node. With a must-take contract in Case 4, there is an economic penalty for not using all available generation from wind even though this source increases the marginal production cost substantially, and this marginal cost sets the market price in a uniform price auction.

NORMAL Wind (Cases 2 and 2UP) as with NO Wind (Cases 1 and 1UP), and even higher with NASTY Wind (Cases 4 and 4UP). It is only with NICE Wind that capacity needed is substantially lower (Cases 3 and 3UP). The underlying reason for this is that storage capacity coupled with wind generation in Cases 3 and 3UP provides a floor for the minimum generation of 35 MW from the wind farm, including the effect of the cutout contingency at very high wind speeds. In addition, less potential wind generation is spilled.

Even though the production cost and price offer of wind generation is set to zero for NORMAL Wind, the maximum amount of wind capacity dispatched (Max Wind Committed) is only 35MW, compared with the true maximum of 105MW due to the high cost of covering the contingency when wind turbines cut out. More wind generation can be used economically when the tie line is upgraded (Case 2UP) or if storage capacity is coupled with wind generation (Cases 3 and 3UP). However, the amount of wind capacity dispatched is not really limited by the physical capacity of the network. In Cases 4 and 4UP, with must-take contracts, all 105MW of wind capacity are dispatched, but the consequence of this is that customers have to pay a lot more in the wholesale market for congestion, and a lot more to maintain System Adequacy.

The overall cost of purchases in the wholesale market for the different scenarios is summarized in Figure 3.2. For NO Wind in Case 1, the total cost to customers is relatively high and most of this total is Net Revenue for conventional generators, above their true operating costs. Operating Costs make up about one fifth of total payments. A small payment in Case 1 goes to Congestion Rents (the difference between payments by customers and payments to generators) but, with the tie line upgrade in Case 1UP, Congestion Rents are negative. With NORMAL Wind and NICE Wind, total payments drop substantially compared to NO Wind, and most reductions come from much lower Net Revenues for conventional generators. Net Revenue for the wind generators is relatively small. Results for NASTY Wind are very different. Operating Costs and Net Revenue for conventional generators are both higher than in Case 1, unless the tie line is upgraded in Case 4UP. Accommodating large quantities of unmitigated wind generation on the network is expensive and does not benefit customers. It is interesting to note that Net Revenue for wind generators is still relatively small.

The sum of the Net Revenues earned by conventional generators and Congestion Rent is the Operating Surplus in the wholesale market, and this quantity represents the amount of money available to cover capital costs. In the same way, Net Revenue for a wind generator can be used to cover investment in a wind farm. Using NO Wind (Case 1) as the basis for comparison, Operating Surplus is much lower for NORMAL and NICE Wind (Cases 2 and 3), and slightly higher for NASTY Wind (Case 4). The Operating Cost in Case 4 is high because the mix of generating capacity dispatched is very different from the least-cost merit order due to network constraints and congestion. In all four cases, upgrading the tie line reduces the Operating Cost and makes it possible to rely more on inexpensive sources of generation.

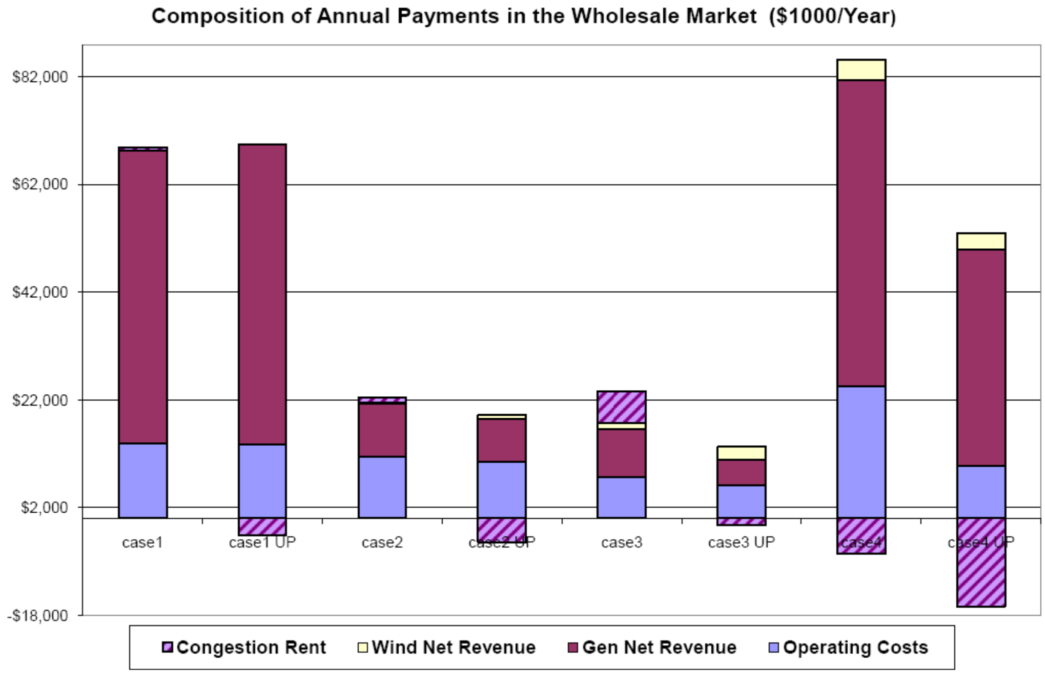

Figure 3.2: The Composition of Payments by Customers in the Wholesale Market

3.5. Determining Amount of Additional Money

The final component of the analytical framework is to describe how much additional money is required by generators above their annual earnings in the Wholesale Market to ensure that they are financially viable. This is the main implication of requiring that an electric delivery system should maintain Financial Adequacy as well as Physical Adequacy. In addition, changes in amounts of congestion rents collected by the System Operator in the Wholesale Market affect how much additional money is needed to pay transmission owners a regulated rate of return on their capital investment in transmission and distribution. Even though the total payment made to transmission owners is the same in all scenarios, the proportion of this amount coming from congestion rents is determined in the analysis.

Under a regulated regime, rates charged to customers are set so that utilities receive enough revenue to cover all operating costs and a fair rate of return of and on the depreciated book value of the capital assets that are considered by the regulators to be "used and useful." This procedure is assumed to still be the appropriate method of paying for transmission and distribution assets in a deregulated market. For merchant generators, however, revenue in a deregulated market comes from 1) being paid nodal prices for their generation and ancillary services in the Wholesale Market[11], and 2) payments for capacity in a Capacity Market, if such a market exists. These generators expect to earn a market rate of return on the market value of their generating assets. Given the physical durability of conventional generating units relative to standard regulatory accounting rates of depreciation, the market value of conventional capacity is typically substantially higher than the book value would have been under continuous regulation[12]. This is a major additional cost that should be compared with any gains in economic efficiency in the Wholesale Market that lower operating costs.

The amount of additional money for a conventional generator is determined by specifying minimum annual earnings needed to maintain Financial Adequacy. In a deregulated market, it is assumed that minimum annual earnings above annual operating costs correspond to the replacement value for each generating unit. Values used in this analysis are shown in Table 3.3. As long as annual earnings in the Wholesale Market are higher than minimum earnings, the generating unit meets the standard of Financial Adequacy and there is no additional money. On the other hand, if annual earnings in the Wholesale Market are lower than minimum earnings, the

[11] These payments may also be made through forward contracts, but contract prices will still reflect expectations of traders concerning future prices in the Wholesale Market. In addition, there may be bilateral contracts that include two-part payments for energy, or an ancillary service, or for capacity.

[12] The late Mike Rothkopf was one of the few economists to raise this issue as an important reason for being skeptical about the widely held belief among academics and regulators that deregulating electric utilities would benefit customers. See Michael H. Rothkopf, "Dealing with Failed Deregulation: What Would Price C. Watts Do?" The Electricity Journal 20(7), pp.10-16, July-August 2007.

difference between minimum earnings and actual earnings measures the amount of additional money. Dividing the amount of additional money by the amount of generating capacity needed for System Adequacy gives the minimum price of capacity ($/MW/Year) needed for Financial Adequacy. In other words, as long as the price paid in a Capacity Market is higher than the minimum price for every conventional generating unit, it is high enough to maintain Financial Adequacy.

The final step in the calculation of the total quantity of additional money for conventional generators is to specify a structure for the Capacity Market. It is assumed, following the structure of the New York market, that the Capacity Market is divided into two regions: Area 1, the urban region; Areas 2 and 3, the rural region. Each region sets its own capacity price, and this price is equal to the highest minimum capacity prices needed for Financial Adequacy for all of generating units in a region. The market price is paid for all generating capacity in a region needed to meet peak system load and maintain System Adequacy. This procedure follows the standard practice used to make payments in a uniform price auction.

The simplest type of additional money goes to transmission owners. It is assumed for all scenarios that transmission owners received $30 million/year to cover all costs for the existing network, including annualized capital costs. Part of this total is paid by the ISO Redistributed in the wholesale market (see Figure 3.2), and the remaining part corresponds to additional money. For scenarios in which the ISO pays more to generators than the amount received from customers, the ISO Redistributed is negative, and corresponding additional money will be more than $30 million/year. However, customers still pay the same total cost of transmission, and the only feature that changes from scenario to scenario is the amount of money contributed in the wholesale market.

For generators, the situation is more complicated because the amount of conventional generating capacity needed for reliability purposes varies from scenario to scenario, as well as total annual operating costs. Nevertheless, the total annualized capital cost of conventional generating units is paid in a manner similar to that for payments for transmission. Some of the money comes from the wholesale market (Gen Net Revenue in Figure 3.2) and the rest is paid as additional money through a Capacity Market. Calculations for determining the amount of additional money in a deregulated market are illustrated in Table 3.3 for the NO Wind scenario.

Table 3.3: Additional Money for Conventional Generators with NO Wind (Case 1)

	1	2	3	4	5	6	7	8
	Minimum Earnings/MW $1000/MW/year	**Required Capacity MW**	**Minimum Earnings $1000/year**	**Actual Earnings $1000/year**	**Difference Actual - Min. $1000/year**	**Missing Money Max(-Diff, 0) $1000/year**	**Price of Capacity $1000/MW/year**	**Capacity Payments $1000/year**
Gen 1	$88	20.00	$1,760	$1,452	-$308	$308	$15	$1,623
	$88	15.42	$1,357	$106	-$1,252	$1,252	**$81**	$1,252
Gen 2	$88	25.00	$2,200	$2,204	$4	$0	$0	$2,029
	$88	25.00	$2,200	$406	-$1,794	$1,794	$72	$2,029
Gen 3	$460	30.00	$13,800	$12,784	-$1,016	$1,016	$34	$5,113
	$131	20.00	$2,620	$845	-$1,775	$1,775	$89	$3,409
Gen 4	$460	35.00	$16,100	$14,775	-$1,325	$1,325	$38	$5,965
	$131	0.00	$0	$0	$0	$0	$0	$0
Gen 5	$460	20.00	$9,200	$5,791	-$3,409	$3,409	**$170**	$3,409
	$230	35.00	$8,050	$2,911	-$5,139	$5,139	$147	$5,965
Gen 6	$460	30.00	$13,800	$9,255	-$4,545	$4,545	$152	$5,113
	$230	27.76	$6,385	$3,796	-$2,589	$2,589	$93	$4,731
TOTAL		**283.18**	**$77,472**	**$54,324**	**-$23,148**	**$23,153**		**$40,639**

Steps used to calculate payments for capacity outlined in Table 3.3 were completed for each scenario. These payments, together with payments to transmission owners, are added to Total Annual Operating Costs to give the Total Annual System Cost charged directly in the wholesale market and, indirectly, as additional money to customers.

In contrast, an ideal regulated allocation would have regulators set rates paid by customers to cover all prudent operating costs and capital costs for conventional generators. These rates typically would include fixed rates for energy and, possibly, for capacity for some customers, and real time rates and capacity rates for other customers. However, effects of different rate structures on load are ignored for all scenarios in this analysis, and the focus is on the differences in Total Annual System Costs for the same annual pattern of load. The main differences in a regulated allocation from procedures used for a deregulated market in Table 3.3 are: 1) Minimum Earnings/MW in Column 1 are determined by the book value of capital rather than market value, and 2) capacity payments cover additional money for each unit in Column 6, and would also confiscate excess profits (i.e. positive differences in Column 5). In other words, even if lower book values in Column 1 are ignored, customers would only pay $23 million/Year (Column 6) under regulation, rather than $40 million/Year (Column 8) in a Capacity Market.

In the next section, Total Annual System Costs paid by customers are calculated for eight wind scenarios for the following three types of market allocation (note that component costs for a given wind scenario in the wholesale market in Figure 3.2 are the same in all three markets)[13]:

1) Mkt1: Deregulated Market paying additional money through a Capacity Market (i.e. like Table 3.3),

2) Mkt2: Paying additional money only (i.e. pay Column 6 instead of Column 8 in Table 3.3),

[13] Customers may not actually pay wholesale prices in a regulated market, but annual operating costs are still the same as in a deregulated market for each wind scenario.

3) Mkt3: Regulated Allocation[14] paying legitimate capital costs using a book value equivalent to 50% of market value (i.e. pay Column 5 using 50% of the values in Column 1 of Table 3.3).

3.6. Total Annual System Costs in Different Scenarios

Typically, generating units in an economically efficient market do not receive enough net revenue in the wholesale market to maintain Financial Adequacy. The mechanism for paying the cost of capital for generating units in the three different scenarios is similar to the manner in which transmission owners are paid[15]. Income needed for Financial Adequacy comes from both Net Revenue in the wholesale market and additional money. In Mkt2, additional money is paid directly to individual generators. In a deregulated market (Mkt1), additional money is paid indirectly through a Capacity Market that results in higher payments than Mkt2. The main difference between Mkt2 and the Regulated Allocation (Mkt3) is that Minimum Earnings/MW for the individual generating units are only half as high as in the other two scenarios.

In all three scenarios, if levels of the different types of generating capacity needed for System Adequacy remain the same, generators' capital costs also stay the same. Lower earnings in the wholesale market are simply offset by higher payments for additional money.[16] Hence, the only effective ways to reduce total annual payments to generators for capital costs in a given scenario are 1) to reduce the amount of conventional capacity needed for System Adequacy, and, to a lesser extent, 2) to

[14] It does not reflect the real regulated market. It simply represents another scenario in the analysis.

[15] The fact that most of the generating units do need additional earnings is consistent with a competitive wholesale market. If all offer prices in the wholesale auction equal true marginal operating costs and the combination of different types of generation is economically efficient, all generating units would have the same amount of additional money/MW equal to the capital cost of the most expensive peaking unit.

[16] In a Regulated Allocation (Mkt3), payments are not actually made in two parts, but rates paid by customers would be set high enough to cover all operating and capital costs.

change the mixture of generating units needed for System Adequacy, 3) to provide incentives to build new capacity at lower costs.

Figure 3.3 summarizes overall results of the analysis for the three different scenarios by showing the composition of Total Annual Systems Costs for the four wind scenarios with no tie line upgrade. The first three components (the lowest three) are Operating Costs, Generator Net Revenue and Wind Net Revenue. For each wind scenario, operating costs are identical for the three different scenarios and payments for additional money are highest in a deregulated market (Mkt1), and lowest in a regulated allocation (Mkt3). Payments made to generators in the wholesale market are substantially lower with NORMAL and NICE Wind (Cases 2 and 3), compared to NO Wind (Case 1), but this reduction for NORMAL Wind is effectively offset by the increase in the amount of additional money paid to conventional generators. This additional money is lower for NICE Wind because less generating capacity is needed to maintain System Adequacy, and, as a result, the Total Annual System Cost is also lower.[17] For NASTY Wind (Case 4), both Operating Costs and additional money for conventional generators are higher than corresponding values for NO Wind. The main conclusion is that focusing on a reduction in the average wholesale price when wind capacity is introduced into a deregulated market, in Figure 3.2, can be very misleading unless effects on additional money needed by conventional generators and transmission owners is also considered.

[17] Total payments made to transmission owners are the same in all scenarios, and payments to wind generators and costs of shedding load are always relatively small.

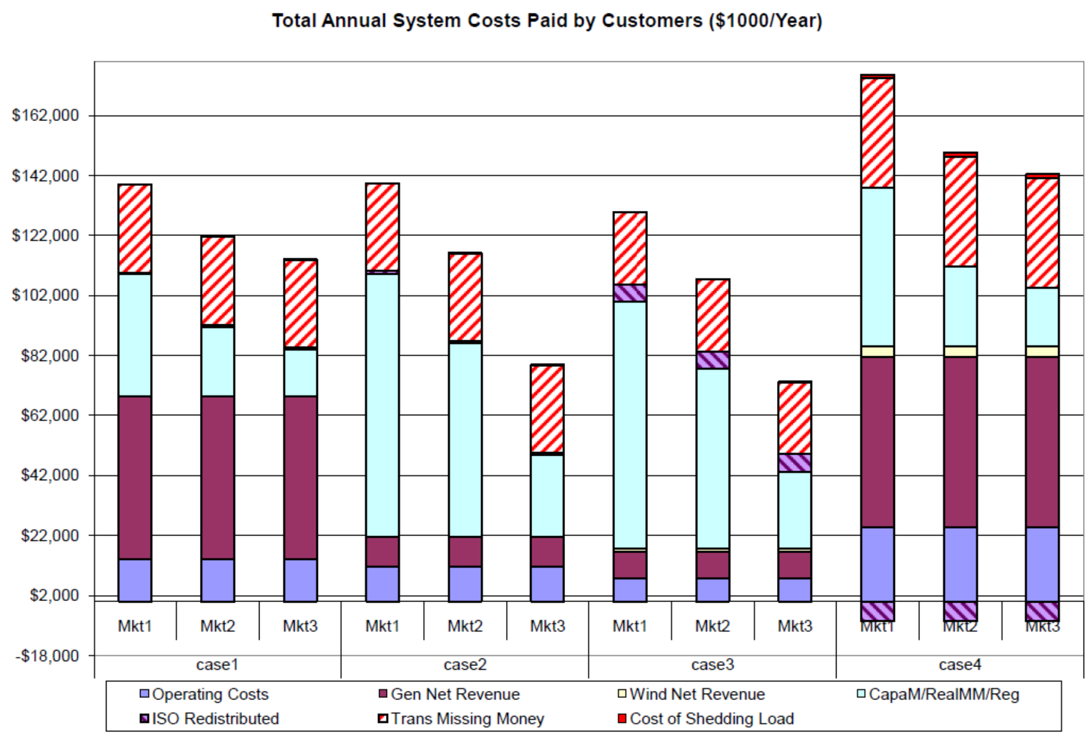

Figure 3.3: The Total Annual System Costs Paid by Customers

The underlying reason for calculating Total Annual System Costs is to determine the viability of making investments in wind capacity and in upgrading a tie line. The economic justification for making an investment corresponds to having a reduction in Total Annual System Costs that is larger than the annual capital cost of financing the investment. Total Annual System Costs for NO Wind are $139, $122, and $114million/Year for Mkt1, Mkt2 and Mkt3, respectively, and Table 3.4 summarizes savings in Total Annual System Costs for a given scenario from investing in the three different wind scenarios (Cases 2-4) compared to NO Wind (Case 1). For all three scenarios, savings for NASTY Wind (Case 4) are negative and there is no economic justification for making such an investment. For NORMAL Wind (Case 2) and NICE Wind (Case3), savings are highest and positive in a regulated allocation (Mkt3) and lowest, and slightly negative, for NORMAL Wind, in a deregulated market (Mkt1).

Finally, additional savings comparing NICE Wind to NORMAL Wind measure the value of having storage capacity mitigate wind variability. This value is smallest in a regulated allocation, because the price of conventional capacity (additional money/MW) is lower than in the other two scenarios.

Table 3.4: Savings in Total Annual System Costs from investment in wind generation

($1000/Year) Case 1-Case s	Case 1	Case 2	Case 3	Case 4
Mkt1	$0	-$218	$9,310	-$30,035
Mkt2	$0	$5,548	$14,139	-$21,340
Mkt3	$0	$35,152	$40,938	-$21,831

Table 3.5 summarizes savings in Total Annual System Costs from upgrading the tie line for Cases 1 – 4 in the three different regimes. Savings from the upgrade are computed for each combination of wind scenario and regime. In a deregulated market (Mkt1), savings are positive in all four wind scenarios. The highest savings are for NASTY Wind (Case 4) because of the need to accommodate the maximum 105MW of wind generation under a must-take contract. Savings are lowest for NICE Wind (Case 3) because storage capacity effectively reduces maximum wind generation on the network (i.e. at high wind speeds, some wind generation is used locally to charge the battery). In fact, savings from upgrading a tie line are negative in Mkt2 and Mkt3 for NICE Wind. Savings from the upgrade are also negative in Mkt2 and Mkt3 for NO Wind (Case 1). Comparing results for NICE Wind and NASTY Wind demonstrates that coupling storage capacity with wind generation is, in effect, a substitute for adding transmission capacity. Once again, using changes in Annual Operating Costs of conventional generators as a guide for determining the benefit of additional transmission capacity may be highly misleading.

Table 3.5: Savings in Total Annual System Costs Available from upgrading a tie line

($1000/Year) Case sUP - Case s	Case 1	Case 2	Case 3	Case 4
Mkt1	$7,177	$6,930	$1,872	$25,593
Mkt2	-$1,959	$531	-$2,765	$24,256
Mkt3	-$1,509	$480	-$1,321	$49,637

3.7. Summary and Conclusion

The objective of this chapter is to illustrate how the SuperOPF can be extended to evaluate financial adequacy of suppliers as well as system adequacy when adding wind capacity to a network. Many studies of the electricity market focus only on lower operating costs in a wholesale market when adding wind capacity. However, costs of maintaining System Adequacy include additional money that is generally paid through some form of Capacity Market. Hence, simply focusing on lower operating costs in a wholesale market is inadequate. Co-optimization capabilities of the SuperOPF determine the amount of conventional generating capacity needed to maintain System Adequacy endogenously. It addresses the physical nature of System Adequacy. Endogenous amounts of generating capacity needed to meet the same peak system load in different scenarios can vary substantially, and these different amounts define the requirements for maintaining System Adequacy on a given network. In general, the total amount of conventional generating capacity needed (dispatched capacity plus upward reserve capacity) may increase when a variable source like wind generation replaces conventional generation. This can occur even when generation from wind displaces a substantial portion of conventional generation.

To evaluate net economic benefits of adding wind generating to a network, total annual earnings above the operating costs for individual generating units in a wholesale market are determined. These earnings are compared with specified minimum levels of earnings, and, if the actual amount earned for any generating unit is less than the corresponding minimum level, there is additional money, implying that an additional source of income is needed to maintain the Financial Adequacy of that unit. Three different types of regime are considered to calculate payments made for additional money. Mkt1 is a deregulated market that has the highest payments because: 1) additional money is determined using market value of generating units, and 2) payments made in a capacity market set the capacity price at the highest amount of additional money/MW for any generating unit. Mkt2 is the same as Mkt1 except that the payment corresponds to actual additional money needed for each generating unit (i.e. there is no capacity market and the implicit price for capacity paid is not the same for every generating unit). Mkt3 is a regulated allocation that has the lowest payments because: 1) additional money is determined by the depreciated book value of generating units rather than market value, and 2) generators are paid actually for incurred capital costs that are assumed to be similar to Mkt2.

For each type of scenario (or regime), the overall implication of evaluating Financial Adequacy for generators is that if a unit needs additional money, reducing earnings of the unit in the wholesale market simply increases the amount of additional money needed. In terms of annual earnings, it is a zero-sum game, unless the threat of wind competition drives the construction cost of conventional generation down. Since adding wind capacity to a network will tend to lower earnings of conventional generators in the wholesale market, these lower earnings will be offset to a large extent by higher amounts of additional money[18], assuming construction costs are identical under all three scenarios.

[18] A similar zero-sum game exists for regulated transmission owners. Some earnings come from congestion rents in the wholesale market, and the rest is made up as additions to retail rates charged to customers.

The case study uses a 30-bus test network to make a comparison of an initial scenario that has only conventional capacity installed (Case 1: NO Wind) with three different scenarios in which a wind farm replaces an existing coal unit in a rural area. The wind farm has three times the rated capacity of the coal unit, and makes up a quarter of total installed generating capacity in the three wind scenarios. These three scenarios correspond to 1) submitting all potential wind generation into wholesale auction at zero cost (Case 2: NORMAL Wind), 2) using on-site storage capacity to modify wind generation and reduce variability and range of output (Case 3: NICE Wind), and 3) using a must-take contract to force the system operator to accept all potential wind generation (Case 4: NASTY Wind). The four cases were also run with an upgrade to the main tie line linking the wind farm to an urban center.

The main results show that a lot of wind generation is spilled with NORMAL Wind because the possibility of having the wind turbines cut out at high wind speeds is high and covering this contingency is very expensive for the network. Operating costs are lower with NORMAL Wind compared to NO Wind, but the amount of conventional generating capacity needed for System Adequacy is slightly higher. More wind generation is used with NICE Wind so that Operating Costs are further reduced. More importantly, addition of storage reduces the amount of generating capacity needed for System Adequacy. With NASTY Wind, even more wind generation is used, but Operating Costs actually increase and the amount of conventional capacity needed also increases substantially. Accommodating large quantities of variable generation from a single node on the network causes many expensive constraints that must be met to balance flows on all transmission lines.

When amounts of additional money are computed, Total Annual System Costs for conventional generators and transmission owners (i.e. ignoring the capital cost of the wind farm) are slightly higher with NORMAL Wind, and a lot higher with

NASTY Wind compared to NO Wind. In other words, customers are worse off in these two cases. Total Annual System Costs are lower with NICE Wind, and this illustrates the potential economic value of using storage to reduce the variability of wind generation. Adding an upgrade to the tie line does reduce Total Annual System Costs in all four cases, but, for NASTY Wind, these costs are still higher than in the initial NO Wind case.

CHAPTER 4

THE ECONOMIC VALUE OF TRANSMISSION LINES

4.1. Introduction

The overall objective of this chapter is to present an analytical framework for determining the economic value of individual transmission lines, and, in particular, to determine how these economic values change when an inherently intermittent source of generation, such as wind capacity, is added to a network. The structure of this chapter includes five additional sections. Section 4.2 describes how the SuperOPF can be used to distinguish benefits of transmission lines for transferring power from maintaining reliability. Section 4.3 presents specifications for a series of scenarios that consider effects of replacing a coal unit by different levels of wind capacity, with the largest wind capacity equal to three times the installed capacity of the coal unit. Since wind capacity causes more congestion on the network when the wind blows, a series of additional scenarios evaluate effects of changing the capacity of selected transmission lines to reduce this congestion. Section 4.4 shows how nodal prices are used to determine annual congestion rents for individual transmission lines for an intact network, and, also, when equipment failures (contingencies) occur.

Congestion rents on the network are treated as one source of income for transmission owners. If these rents are too low, there will be additional money that must be paid by customers outside the Wholesale Market to ensure that transmission owners are financially viable. Additional money for both generators and transmission owners contributes to the total annual system cost of maintaining System Adequacy.

The results for all scenarios are presented in Section 4.5. Overall conclusions of the analysis are summarized in Section 4.6.

4.2. Using the SuperOPF to Evaluate Transmission

In Chapter 3 (Section 3.2), description of how the SuperOPF can be used to evaluate system adequacy when adding wind capacity to a network is presented, along with how NERC Reliability standards can be achieved using the SuperOPF. Later in Chapter 3, how endogenous amounts of conventional capacity needed to maintain reliability by using the SuperOPF are described, and amounts of additional money for those generators are presented. In this section, how the SuperOPF can be used to distinguish benefits of transmission lines for transferring power from maintaining reliability is described. The conventional economists' view of transmission lines in a network is that they are there to transfer electricity from inexpensive sources to expensive sinks. This concept works reasonably well when the topology of a network is radial, like the Western Interconnection that has a major transmission corridor connecting inexpensive hydro sources in the Pacific Northwest to urban centers in California. However, when the topology of a network is meshed, as with the Eastern Interconnection, this conventional representation falls apart. In a meshed network, there are multiple ways that electricity can flow from a specific source to a specific sink, and these flows do not necessarily respect market logic, because they are governed by the laws of physics. Kirchhoff's laws for current and voltage determine energy flows on every transmission line in an AC network given injections and withdrawals of real and reactive power at every node.

The redundancy of multiple pathways between sources and sinks in a meshed network is nothing new from the point of view of system operators. These redundancies are important for maintaining reliability of supply. This implies that there is another level of complexity for economists to consider when determining costs and benefits of transmission lines[19]. Hence, the conventional method of valuing transmission lines is inadequate.

The objective function of the SuperOPF, described in Chapter 2 (Section 2.5), determines the optimal AC dispatch and nodal prices in an energy-reserve market using CO-OPT modified to include the cost of LNS, and also distinguishes between positive and negative reserves for both real and reactive power. A high VOLL is specified as the price of LNS. The objective function minimizes the total expected cost (the combined production costs of energy and reserves) for a base case (intact system) and a specified set of credible contingencies (line-out, unit-lost, and high load) with corresponding probabilities of occurrence. It also allows load shedding at a high VOLL in all contingencies. Corresponding nodal prices reflect patterns of dispatch for the intact system as well as for the system when contingencies occur.

Transmission congestion revenues for a specific transmission line are calculated by multiplying the difference in nodal prices times the quantity of energy transferred. Using the SuperOPF, congestion revenues for each transmission line can be split into two parts. First, congestion revenues coming from the intact network represent the value of transferring energy, and, second, congestion revenues coming from contingency cases represent the value of maintaining reliability. For example, 98% of the time, the system is in the intact system and 2% of the time, contingencies could occur. Suppose that the quantity of energy transferred in a transmission line is 50MW; the nodal prices difference under the intact system is $50/MWh, and under the

[19] For generating units, purchases of spinning reserves help to make it feasible for system operators to avoid blackouts when equipment failures (contingencies) occur. This type of flexibility in determining how generating units are dispatched for generation and reserves is not yet practical for transmission lines. However, new Flexible AC Transmission Systems (FACTS) have been developed, but are not widely deployed at this time.

contingencies is \$4,000/MWh. Overall congestion revenues are \$6,450/h (98%*\$50*50 + 2%*\$4,000*50). Corresponding congestion revenues for transferring power are \$2,450/h (98%*\$50*50), and corresponding congestion revenues for maintaining reliability are \$4,000/h (2%*\$4,000*50).

The following section describes characteristics of the 30-bus test network used in the case study and specifications for the simulations. The basic objective of this analysis is to evaluate the effects of replacing an existing coal unit with different levels of wind capacity. Different scenarios are evaluated for individual transmission lines to determine: 1) congestion rents coming from transferring power, and 2) congestion rents coming from maintaining reliability. In addition, the analysis determines the economic benefit of upgrading (or downgrading) a transmission line to transfer more (or less) wind generation from a remote location to an urban center.

4.3. Specifications for the Scenarios

4.3.1 The Test Network and Scenarios for Wind Generation

The test network and scenarios for wind generation in this chapter follow the similar set up as in the chapter 3 (section 3.3) except that the 35MW coal unit at Generator 6 is replaced in four steps by wind capacity, with corresponding reductions in coal capacity. Amounts of wind capacity and coal capacity in the five scenarios are summarized in Table 4.1.

Table 4.1: Specifications of the Wind Penetration Levels

	New Wind Capacity	Coal Unit Capacity
No wind ("0")	0 MW	35 MW
1st wind penetration level ("1")	26 MW	26 MW
2nd wind penetration level ("2")	53 MW	18 MW
3rd wind penetration level ("3")	79 MW	9 MW
4th wind penetration level ("4")	105 MW	0 MW

The justification for choosing 105MW of wind capacity in the highest wind penetration level is that it approximates current procedures used by regulators to de-rate the amount of installed wind capacity to the expected amount of capacity that will be available to meet peak system load. A coal plant may have an availability rating of over 90% but a wind farm is likely to have a rating of less than 20%. Hence, the implicit use of 33% for relative availability of wind capacity compared to a coal unit is relatively high, and this value was chosen to avoid having the wind farm overwhelm the capacity of the network. In spite of adopting this strategy, a lot of potential wind generation is spilled even if wind capacity is submitted into the wholesale auction at an offer price of zero.

For this case study, the peak system load is specified at a level that causes some load shedding in some contingencies, and the expected amount of LNS varies in the different scenarios. This load shedding occurs even though the maximum amount of generating capacity dispatched is lower than the total installed capacity. In other words, the physical limitation of the existing transmission network makes it impossible or excessively expensive to transfer additional real energy from generators with surplus capacity to the locations where it is needed. The installed capacities and locations of different types of generating units are shown in Table 4.2, with their production costs.

Table 4.2: Installed Generating Capacity of the Initial System by Type and Location and Production Costs

Area	Nuclear/ Hydro	*Coal*	Oil	Combined Cycle Gas	Gas Turbine	Total by Area
1	0	0	65MW	0	45MW	**110MW**
2	50MW	70MW	0	0	0	**120MW**
3	65MW	0	0	40MW	0	**105MW**
Total by Type	**115MW**	**70MW**	**65MW**	**40MW**	**45MW**	**335MW**
Production Cost	**$5/MWh**	**$25/MWh**	**$95/MWh**	**$55/MWh**	**$80/MWh**	**-**

4.3.2 Contingencies Considered

Specific contingencies included in the SuperOPF are listed in Table 4.3. These include failures of individual generators and transmission lines, as well as uncertainty about the actual level of load associated with errors of the forecasted load. When wind capacity is added to the network, this type of uncertainty about actual outcomes is exacerbated, and, for this case study, combined forecasting errors for load and wind generation are represented by four possible outcomes (Wind 1-4 in Table 3.1). Each outcome specifies a potential level of generation from a wind farm and the corresponding pattern of loads, and each outcome has a specified probability of occurring. This information is summarized in chapter 3, table 3.1..

For generators and lines, there are only two possible outcomes. The first outcome is to perform as required in the optimum dispatch, and the second is to fail completely. However, probability of failure is very low (0.2% for each failure in this case study), and, as a result, the probability that each piece of equipment will perform as required is 99.8%. Since there are 15 failures identified in Table 4.3, the expected number of failures is 3 in 100 periods, since individual failures and periods are specified to be statistically independent. In other words, the system is expected to be intact 97% of the time. In contrast to high probabilities that equipment will not fail, the probability that a forecasted level of wind generation will actually be realized is relatively low.

Hence, it is unlikely that one of the four different outcomes for wind generation (Wind 1-4) will have a dominant probability. In addition, the range of possible outcomes is large, and, as a result, one would expect that the quantity of reserves needed to maintain Operating Reliability should increase as more wind capacity is installed. This phenomenon has already been observed in Europe, and levels of operating reserves have increased by almost 10% in some countries.

Table 4.3: Contingencies Used in the Case Study*

```
0  = wind 1 (root case)
1  = wind 2
2  = wind 3
3  = wind 4
4  = line 1  : 1-2   (between gens 1 and 2, within area 1)
5  = line 2  : 1-3   (from gen 1, within area 1)
6  = line 3  : 2-4   (from gen 2, within area 1)
7  = line 5  : 2-5   (from gen 2, within area 1)
8  = line 6  : 2-6   (from gen 2, within area 1)
9  = line 36 : 27-28 (main tie, areas 1-3)
10 = line 15 : 4-12  (main tie, areas 1-2)
11 = line 12 : 6-10  (other tie, areas 1-3)
12 = line 14 : 9-10  (other tie, areas 1-3)
13 = gen 1
14 = gen 2
15 = gen 3
16 = gen 4
17 = gen 5
18 = gen 6
```

* Probabilities for Contingencies 0 - 3 are summarized in Table 3.1 (chapter 3)
Probabilities for each of Contingencies 4 -18 is 0.2%

4.4. Transmission Congestion Revenues: Myths and Reality

4.4.1 Measuring the Transmission Congestion Revenues for a Typical Hour

Transmission congestion revenues for a specific transmission line are calculated by multiplying the difference in nodal prices times quantity of energy transferred. Typically, transmission congestion revenues are positive because energy generally flows from inexpensive sources to expensive sinks. However, in an AC meshed network, transmission congestion revenues can also be negative when energy flows from an expensive source to an inexpensive sink. In this section, results from one annual simulation are used to provide an example of positive and negative congestion revenues. Furthermore, congestion revenues for each transmission line are split into two parts. First, congestion revenues coming from the intact network represent the value of transferring energy, and, second, congestion revenues coming from contingency cases represent the value of maintaining reliability.

Transmission congestion revenues for transferring energy on a specific transmission line AB (Node A is the source and Node B is the sink) are calculated as follows[20]:

1) Flow on AB = (Energy at Node A – Energy at Node B)/2,

2) Congestion Revenue for AB = Flow on AB *(nodal price at Node B – nodal price at Node A).

Given these two values, the "Implied Price" is defined as follows:

[20] The source (Node A) provides positive energy to Line AB, and the sink (Node B) withdraws negative energy from Line AB. The difference in nodal prices is defined as the nodal price at sink B minus the nodal price at source A.

Implied Price for AB = Congestion Revenue for AB / |Flow on AB|.

If the implied price is positive, energy flow is consistent with market logic and goes from an inexpensive source to an expensive sinks. If the implied price is negative, energy flows from an expensive source to an inexpensive sink, and therefore, this violates market logic.

Figure 4.1 shows hourly Implied Prices for NORMAL WIND (Level 1, see Table 4.1) over an annual simulation. Hourly loads for a year are ranked and aggregated into 100 bins for the simulations. For each bin/level, are four intact cases (Contingencies 0-3 in Table 4.3) and 15 contingencies/failures (Contingencies 4-18 in Table 4.3), and in addition, three different wind forecasts (Table 3.1, chapter 3). Consequently, for each transmission line, there are 100x4x3 = 1200 Implied Prices for the intact network (solid blue circles), and 100x15x3 = 4500 (dotted blue crosses) for the contingencies/failures. The horizontal axis represents the number of the transmission line in Figure 4.1, and the vertical axis measures the Implied Price ranging from -$4,000/MWh to +$16,000/MWh. This is a very large range because typical nodal prices are between $0/MWh and $100/MWh.

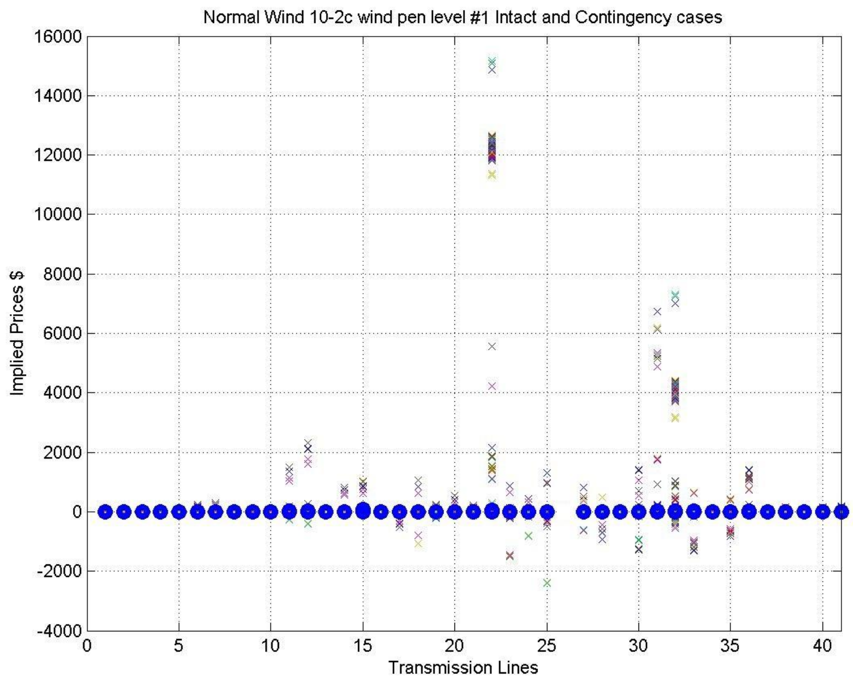

Figure 4.1: Hourly Implied Prices for individual transmission lines using NORMAL Wind (Level 1) for the intact (circles) and contingency (crosses) cases.

The results show that there is a major difference in Implied Prices between intact cases and contingency cases. Nodal prices for intact cases are all relatively small and appear as a single observation in Figure 4.1, but this is not the case for contingencies. First, there are a number of negative prices, and, second, some of the prices are very high, particularly for Line 22. Even though the probability of having a specific contingency/failure is very small (0.2%), expected congestion rent can still be substantial (e.g. 0.002x15000 = $30/MWh). It should be noted that the very high Implied Prices are associated with shedding some load at VOLL and are not caused by speculation. Offers submitted into the wholesale auction by all generating units are equal to the true marginal production costs in Table 4.2. Since the price scale in Figure 4.1 is determined by the very high prices for some of the contingency cases, Implied Prices for the intact cases only are shown again in Figure 4.2 to illustrate how these prices vary.

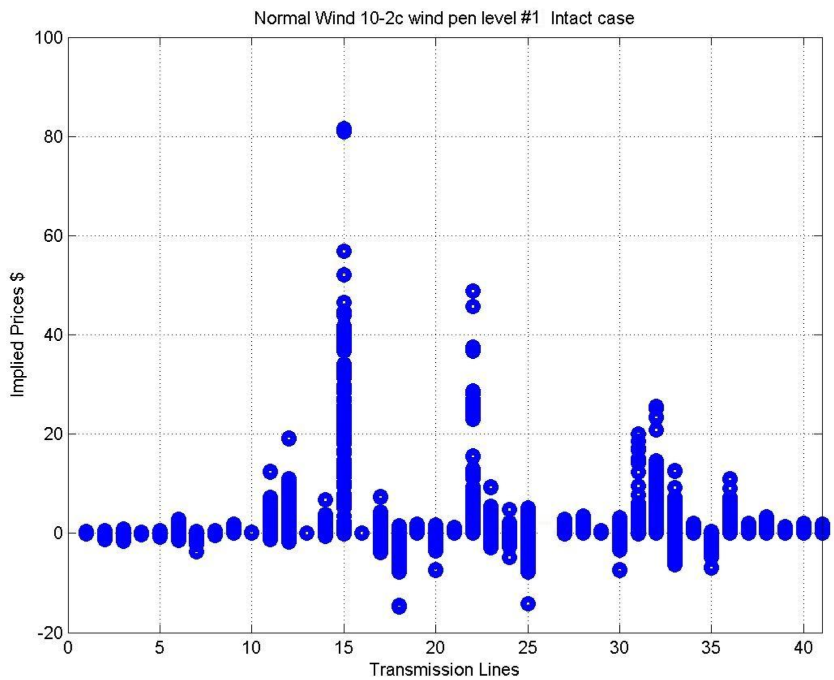

Figure 4.2: Hourly Implied Prices for individual transmission lines using NORMAL Wind (Level 1) for the intact cases.

Results in Figure 4.2 show that Implied Prices for intact cases can also be negative; they range from -\$20/MWh to +\$80/MWh. For example, most Implied Prices for Line 18 are negative. Line 15, linking Area 2 to Area 1 (the urban center), is the best example of a single tie line that transfers energy between two regions, and this tie line has the highest average Implied Price in Figure 4.2. The other important tie lines linking Area 1 to Area 3 are Lines 12, 14 and 36, and Implied Prices for these tie lines are also generally positive, but not as large as the Implied Prices for Line 15. However, Implied Prices for the two tie lines linking Areas 2 and 3 have quite different characteristics. Although Line 32 has positive Implied Prices like the other tie lines, most Implied Prices for Line 25 are negative. On a meshed AC network, it is difficult to predict whether the Implied Price of transferring energy is going to be positive or negative for a specific transmission line, even when the network is intact. However, occurrences of negative Implied Prices are likely to be more localized on a large network like the Eastern Interconnection than on a small network like the test network in Figure3.1.

Table 4.4 presents additional information about Implied Prices for Line 15 (the single tie line linking Area 1 to Area 2 that has positive Implied Prices) and Line 25 (the only one of the three tie lines linking Area 2 and Area 3 that has mostly negative Implied Prices). Implied Prices for both tie lines are shown for the four intact cases and 15 contingencies/failures for the three highest levels of load (Load 1, Load 2 and Load 3). Implied Prices vary substantially for each tie line over the 19 different cases and the three levels of load. The four intact cases (Contingencies 0-3) represent different realizations of wind generation (shown in Table 3.1), and these cases have a combined probability of occurring of 97%. Line 15 has Implied Prices of roughly \$35/MWh for the four intact cases, and these cases provide the dominant source of annual congestion revenues. In contrast, corresponding Implied Prices for Line 25 are small and negative. In fact, Implied Prices for Line 25 are relatively small and negative for most cases. However, large Implied Prices occur when Line 15 fails (Contingency 10) and Generator 3 fails (Contingency 15). The three Implied Prices for Line 25 in Table 4.4 are large and negative for Contingency 10, but, for Contingency 15, the Implied Price is large and negative for Load 1 and Load 2, but large and positive for Load 3. In spite of these sign reversals, these two contingencies/failures account for a substantial proportion of annual congestion revenues for Line 25. For Line 15, Implied Prices are all large and positive for

Contingency 15, and, as expected, are at zero for Contingency 10 when this transmission line fails.

Table 4.4: Implied Prices for Line 15 and Line 25 using NORMAL WIND (Level 1) for intact cases and contingencies using the three highest levels of load

	Line 25			Line 15		
Intacts and Conts	**Load 1**	**Load 2**	**Load 3**	**Load 1**	**Load 2**	**Load 3**
0 (Intact 1)	$4	$3	-$5	$27	$41	$25
1 (Intact 2)	-$4	-$6	-$6	$27	$38	$39
2 (Intact 3)	-$5	-$5	-$5	$31	$31	$31
3 (Intact 4)	-$5	-$5	-$5	$31	$31	$31
4 (Contingency 1)	$0	-$1	-$1	$1	$9	$10
5 (Contingency 2)	$0	-$1	-$2	$3	$11	$12
6 (Contingency 3)	$0	-$2	-$2	$2	$12	$11
7 (Contingency 4)	$0	-$2	-$3	$3	$15	$17
8 (Contingency 5)	$0	-$3	-$4	$4	$23	$25
9 (Contingency 6)	-$20	-$21	-$21	$118	$117	$117
10 (Cont. 7- Line 15 out)	-$2,376	-$2,375	-$341	$0	$0	$0
11 (Contingency 8)	-$6	-$7	-$9	$39	$49	$62
12 (Contingency 9)	-$11	-$11	-$10	$116	$116	$116
13 (Contingency10)	$0	-$1	-$1	$2	$10	$11
14 (Contingency 11)	-$1	-$4	-$4	$11	$27	$24
15 (Cont. 12-Gen. 3 out)	-$394	-$503	$1,306	$761	$1,022	$849
16 (Contingency 13)	$1	$1	$1	$0	$0	$0
17 (Contingency 14)	$2	$2	$2	$0	$0	$0
18 (Contingency 15)	$2	$1	$1	$1	-$1	-$1

4.4.2 Measuring Expected Annual Congestion Revenues

Optimal dispatch and nodal prices determined by the SuperOPF make it possible to split expected annual congestion revenues into two parts. The first part is expected annual congestion revenue from transferring power (in the four intact cases), and the second is expected annual congestion revenue from maintaining reliability (in the 15 contingency/failure cases). In addition, Implied Prices can be positive or negative, and expected annual congestion revenues can be divided into two parts. E+ measures congestion revenues for positive Implied Prices that are consistent with market logic, and E- measures congestion revenues from the negative Implicit Prices that are inconsistent with market logic.

Table 4.5 on the next page shows the composition of expected annual congestion revenues for each of the transmission lines grouped by Area (tie lines are highlighted). Components are E+ and E- for both intact cases and contingency/failure cases. For Line 7, for example, values of E+ and E- for contingency cases are \$3,717/year and -\$56/year, respectively, for a total of SumCont = \$3,661/year, and corresponding values of E+ and E- for intact cases are \$3,026/year and -\$22,577/year, respectively, for a total of SumInt = -\$19,551/year and an overall annual total of -\$15,889/year.

All reported revenues in Table 4.5 have been weighted by appropriate probabilities of contingencies and wind realizations. Generally, expected annual congestion revenue from contingencies is small compared to revenue from intact cases, because probabilities of contingencies occurring are small. Tie lines (Line 12, Line 14, Line 36 and Line 15) linking the urban center (Area 1) to Areas 2 and 3 are all positive with the largest part coming from transferring energy in intact cases. Negative congestion revenues are relatively small and overall results for these four tie lines are consistent with market logic, implying that energy generally flows from inexpensive sources in Areas 2 and 3 to expensive sinks in Area 1.

Contrasting results for the two tie lines (Line 25 and Line 32) connecting Areas 2 and 3 are harder to interpret. Total expected annual congestion revenue for Line 25 has a large negative value even though corresponding revenue for Line 32 has a large positive value. However, both tie lines have important effects on reliability since the largest component of total expected annual congestion revenue comes from contingency cases. The reliability component is positive for Line 32 (SumCont = \$540,426/year) and negative for Line 25 (SumCont = -\$82,084/year). The physical topology of the network under the different contingencies and the laws of physics determine these contrasting results.

Table 4.5: Composition of Expected Annual Congestion Revenues ($/year) for individual transmission lines using NORMAL Wind (Level 1).

		Cont			Intact			
	Line	E+	E-	Sum Cont	E+	E-	Sum Int	Total
Area 1	1	$1,092	$0	$1,092	$1,222	($9)	$1,213	$2,305
	2	$960	($27)	$933	$2,151	($1,528)	$623	$1,556
	3	$748	($169)	$578	$6,634	($2,552)	$4,082	$4,661
	4	$142	($6)	$136	$1,004	($300)	$704	$840
	5	$1,487	($2)	$1,485	$995	($506)	$489	$1,974
	6	$2,251	($2)	$2,249	$8,194	($100)	$8,093	$10,342
	7	$3,717	($56)	$3,661	$3,026	($22,577)	($19,551)	($15,889)
	8	$1,403	($1)	$1,402	$1,105	($171)	$934	$2,336
	9	$3,693	($46)	$3,647	$46,229	$0	$46,229	$49,876
	10	$1,244	($1,220)	$24	$8,208	$0	$8,208	$8,232
	11	$1,477	($34,232)	($32,755)	$87,083	($7,862)	$79,222	$46,467
	13	$0	$0	$0	$0	$0	$0	$0
	40	$4,113	($4)	$4,108	$13,226	$0	$13,226	$17,335
	41	$8,611	$0	$8,611	$22,304	$0	$22,304	$30,916
	12 (1<->3)	**$1,629**	**($29,469)**	**($27,840)**	**$76,600**	**($6,741)**	**$69,859**	**$42,019**
	14 (1<->3)	**$829**	**($17,352)**	**($16,523)**	**$46,990**	**($3,958)**	**$43,032**	**$26,508**
	36 (1<->3)	**$93,875**	**$0**	**$93,875**	**$148,999**	**$0**	**$148,999**	**$242,873**
	15 (1<->2)	**$9,649**	**($613)**	**$9,036**	**$1,723,706**	**($1,087)**	**$1,722,619**	**$1,731,655**
Area 2	16	$0	$0	$0	$0	$0	$0	$0
	17	$178	($2,247)	($2,068)	$2,936	($380)	$2,556	$488
	18	$2,288	($5,261)	($2,973)	$9,886	($51,872)	($41,987)	($44,960)
	19	$4,147	($7,246)	($3,099)	$20,280	$0	$20,280	$17,182
	20	$1,742	($211)	$1,531	$6,610	($10,838)	($4,228)	($2,697)
	21	$2,094	($3,290)	($1,197)	$9,847	$0	$9,847	$8,650
	22	$1,287,617	$0	$1,287,617	$254,517	$0	$254,517	$1,542,133
	23	$2,024	($136,438)	($134,413)	$32,712	($10,899)	$21,813	($112,600)
	24	$270	($36,686)	($36,416)	$2,441	($826)	$1,615	($34,801)
	30	$18,910	($118,754)	($99,844)	$44,282	($107,747)	($63,465)	($163,309)
	25 (2<->3)	**$882**	**($82,966)**	**($82,084)**	**$13,648**	**($11,520)**	**$2,127**	**($79,957)**
	32 (2<->3)	**$541,943**	**($1,517)**	**$540,426**	**$197,517**	**$0**	**$197,517**	**$737,943**
Area 3	27	$56,632	($13)	$56,619	$60,056	($5)	$60,051	$116,670
	28	$37,951	($112)	$37,839	$42,228	$0	$42,228	$80,067
	29	$14,516	($304)	$14,212	$23,124	$0	$23,124	$37,336
	31	$126,864	($2)	$126,863	$34,012	($1)	$34,011	$160,874
	33	$18,914	($1,822)	$17,092	$3,410	($3,779)	($369)	$16,723
	34	$780	($207)	$573	$6,223	$0	$6,223	$6,796
	35	$31,210	($1,764)	$29,446	$2,027	($9,512)	($7,485)	$21,961
	37	$1,932	($489)	$1,444	$15,719	$0	$15,719	$17,163
	38	$3,717	($911)	$2,806	$30,470	$0	$30,470	$33,275
	39	$781	($182)	$599	$6,476	$0	$6,476	$7,075
TOTAL		**$2,292,314**	**($483,620)**	**$1,808,695**	**$3,016,097**	**($254,771)**	**$2,761,326**	**$4,570,020**

Another transmission line that is of interest is Line 22 in Area 2 because it has very large positive Implied Prices in contingencies (see Figure 4.1) and relatively large positive Implied Prices in intact cases (see Figure 4.2). In fact, by far the largest component of expected annual congestion revenue is E+ = $1,287,617/year for contingencies (Table 4.5). Hence, Line 22 is an example of a transmission line that is needed primarily for maintaining reliability. For many other transmission lines, however, congestion revenues for contingencies and intact cases have opposite signs (e.g. Lines 7, 11, 12, 14, 17, 19, 20, 21, 23, 24, 28, 33 and 36). Overall, results show that the network has a large positive benefit of over $4.5 million/year, but results in Table 4.5 also demonstrate that evaluating benefits of individual transmission lines is inherently complex because any selected transmission line may have positive benefits in some situations and negative benefits in others.

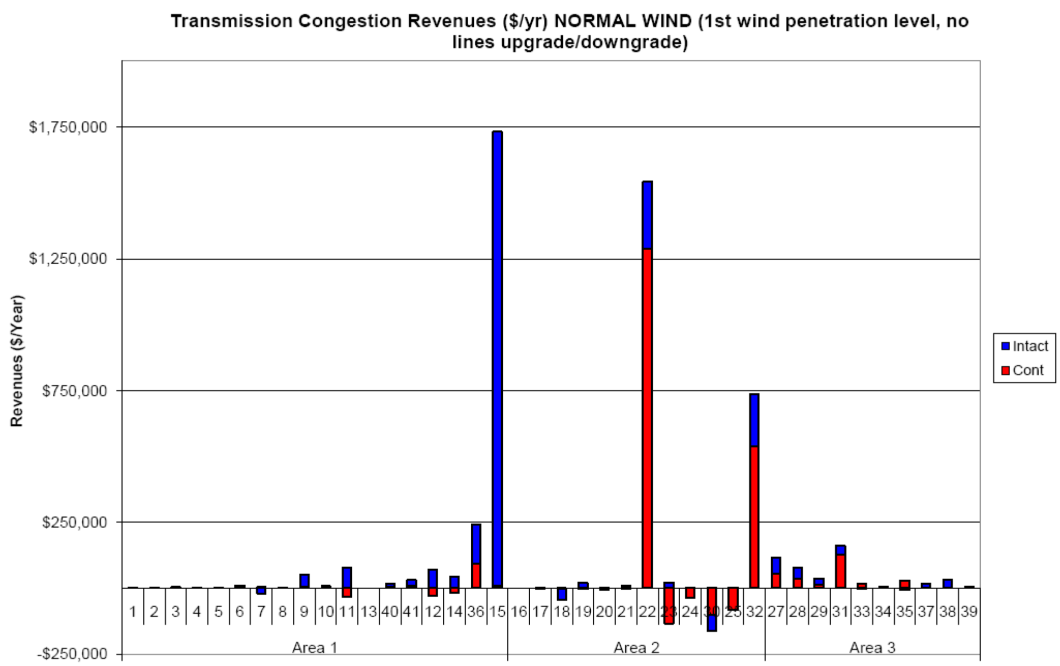

Figure 4.3: Expected Annual Congestion Revenues ($/year) for individual transmission lines using NORMAL Wind (Level 1)

Figure 4.3 summarizes results in Table 4.5 for expected annual congestion revenues for each individual transmission line. The top (blue) part of each bar accounts for congestion revenues for transferring energy (intact cases), and the bottom (red) part accounts for the congestion revenues for maintaining reliability (contingencies). These results illustrate two important policy implications. First, owners of individual transmission lines earn very different amounts from congestion revenues, and annual earnings for Lines 15, 22 and 32 are by far the largest. Second, sources of congestion revenues differ markedly. Almost all earnings for Line 15, linking Area 2 to Area 1, come from transferring energy (intact cases) while earnings for Lines 22 and 32 come mainly from maintaining reliability (contingencies). Some transmission owners earn almost nothing (e.g. Line 1, Line 2 and Line10, and some other owners even lose money (e.g. Line 23, Line 30 and Line 25).

4.4.3 Amount of Additional Money Needed for Financial Adequacy

The final component of the analytical framework is to determine how much additional money is required above expected annual earnings in the Wholesale Market to ensure that both generators and transmission owners are financially viable. Since there is no guarantee that expected annual earnings for either transmission owners or generators will be sufficient to cover their capital costs, the difference between annual earnings needed above operating expenses for financial viability and annual earnings in the Wholesale Market measures the amount of supplementary money. In addition, the amount of congestion rent (difference between total annual payments made by customers and total payments made to generators) collected by the System Operator in the Wholesale Market does not necessarily equal expected annual congestion revenue for the network described in the previous section. Even if the total payment made to transmission owners is the same in all scenarios, the proportion of this amount coming from congestion rents changes in different scenarios. In the end, customers will cover all costs of supporting transmission owners and generators by paying for energy purchased and additional costs in their bills that cover additional money for generators as well as the payments for transmission, distribution, and billing. Since transmission and distribution networks are still regulated, the expected annual congestion revenues for transmission lines discussed in the previous section may be quite different from payments actually made by customers to cover costs of transmission. In the simulations presented in Section 4.5, transmission owners receive total annual payments of $30 million/year in every scenario.

Table 4.7: Minimum Annual Earnings for Financial Adequacy of Generators(EIA 2000)

MINIMUM ANNUAL EARNINGS			Installed Capacity MW	Minimum Earnings $1000/MW/Year
Area 1	**Gen 1**	Gas Turbine	20	$88
		Oil	35	$88
	Gen 2	Gas Turbine	25	$88
		Oil	30	$88
Area 3	**Gen 3**	Nuclear/Hydro	30	$300
		Combined Cycle Gas	20	$131
	Gen 4	Nuclear/Hydro	35	$300
		Combined Cycle Gas	20	$131
Area 2	**Gen 5**	Nuclear/Hydro	20	$300
		Coal	35	$230
	Gen 6	Nuclear/Hydro	30	$300
		Coal	35	$230

Under a regulated regime, rates charged to customers are set so that utilities receive enough revenue to cover all operating costs and a fair rate of return of and on the depreciated book value of capital assets considered by regulators to be "used and useful." For merchant generators, however, revenue in a deregulated market comes from; 1) being paid nodal prices for their generation and ancillary services in the Wholesale Market[21], and 2) payments for capacity in a Capacity Market, if such a market exists. These generators expect to earn a market rate of return on the market value of their generating assets. Given the physical durability of conventional generating units relative to standard regulatory accounting rates of depreciation, the market value of conventional capacity is typically substantially higher than the book value would have been if regulation had continued[22]. This additional money is a major additional cost for customers that should be compared with any gains in economic efficiency in the Wholesale Market that lower operating costs.

The amount of additional money for a generator is determined by specifying minimum annual earnings needed to maintain the Financial Adequacy of conventional generating units. It is assumed that minimum annual earnings above annual operating costs correspond to the replacement value for each generating unit. Values used in the analysis are shown in Table 4.7. As long as annual earnings in the Wholesale Market are higher than minimum earnings, the generating unit meets the standard of Financial Adequacy and there is no additional money. On the other hand, if annual earnings in the Wholesale Market are lower than minimum earnings, the difference between minimum earnings and actual earnings measures the amount of additional money. Dividing the amount of additional money by the minimum generating capacity gives the minimum price of capacity ($/MW/Year) needed for Financial Adequacy. In other words, as long as the price paid in a Capacity Market is larger than this minimum price, it is high enough to ensure Financial Adequacy of all of the generating units.

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[21] These payments may also be made through forward contracts, but contract prices will still reflect expectations of traders about future prices in the Wholesale Market. In addition, there may be bilateral contracts that include two-part payments for energy, or an ancillary service, and for capacity.

[22] The late Mike Rothkopf was one of the few economists to raise this issue as an important reason for being skeptical about the widely held belief among academics and regulators that deregulating electric utilities would benefit customers. See Michael H. Rothkopf, “Dealing with Failed Deregulation: What Would Price C. Watts Do?” The Electricity Journal 20(7), pp.10-16, July-August 2007.

The final step in the calculation of the total amount of additional money for conventional generators is to specify a structure for the Capacity Market. It is assumed, following the structure of the market in New York State, that the Capacity Market is divided into two regions: 1) Area 1, the urban region, and 2) Areas 2 and 3, the rural region. Each region sets its own capacity price and this market price is equal to the highest of the minimum capacity prices needed for Financial Adequacy for all generating units in a region. The market price is paid for all generating capacity in a region that is needed to meet peak system load and maintain System Adequacy. This procedure follows the standard practice used to make payments in a uniform price auction.

4.5. Results of Simulations

4.5.1 Importance of Calculating Total Annual System Costs

The underlying objective is to evaluate system effects of replacing 35MW of installed coal capacity at Node 13 (Generator 6) by five different levels of wind capacity, ranging from 0MW to 105MW. This objective represents the type of policy option that regulators implicitly consider when setting a target for increased penetration of wind capacity to meet, for example, a Renewable Portfolio Standard. Earlier research (Mount, Lamadrid et al. 2009) has shown that the main effects of adding wind capacity are to 1) increase the amount of reserve generating capacity needed to maintain Operating Reliability, 2) reduce the total operating cost of meeting load, 3) reduce annual capacity factors for most conventional generating units, and, as a result 4) increase the amount of additional money paid to generators. Implications of adding wind capacity show why it is so important to determine the amount of generating capacity needed to meet System Adequacy endogenously. Furthermore, modifying capacity of a transmission line will have direct effects on earnings of generators, as well as transmission owners. For a given network topology, the amount of generating capacity needed to maintain System Adequacy can change for different scenarios, but, in contrast, capacities of transmission lines remain the same. This is why expected annual congestion revenues for individual transmission lines described in the previous section can change sign when operating conditions (e.g. a failure occurs) change on the network, and it is unlikely that congestion revenues will always be positive for a given transmission line under all operating conditions.

Although the objective is to determine the economic value of transmission lines, it is essential to consider the effect on Total Annual System Costs. The change in this total when network topology is modified determines whether the modification is a net economic benefit for the network and for customers, since modifying the network will affect earnings of both generators and transmission owners. Once the need for maintaining Financial Adequacy is recognized as important, it follows that increased benefits from modifying a network come primarily from: 1) reducing total annual operating costs (mainly for fuels) of generation and transmission, and 2) reducing the amount of additional money by reducing the amount of generation capacity needed to maintain Operating Reliability[23] (assuming costs of the transmission network are fixed). It is not correct to treat, as some analysts do, lower wholesale prices as an indication of positive system benefits because these lower prices may well be more than offset by higher payments for additional money.

4.5.2 Specified Modifications of the Transmission Network

The focus of the analysis in the next sub-section is on determining how changing the characteristics of the network shown in Figure 3.1 affects the Total Annual System Costs of meeting the same annual pattern of loads. The objective of this sub-section is to provide a rationale for selecting specific modifications of the network for evaluation. For any specified scenario, the change in the Total Annual System Costs from upgrading a particular transmission line, for example, can be determined, and a reduction in this cost should be larger than the annualized cost of financing the upgrade to make the investment financially viable. Similarly, the annualized cost of building new wind turbines should be lower than the corresponding reduction in Total Annual System Costs to make this investment economically beneficial.

[23] In this analysis, the amount of conventional generating capacity committed to meet the highest system peak load is used to determine the amount of capacity needed to meet Adequacy standards and be eligible for payments to maintain Financial Adequacy

For any given network configuration, three different types of wind quality are evaluated, and these three types are NORMAL Wind, NICE Wind (i.e. wind generation coupled with storage batteries) and NASTY Wind (i.e. must-take contracts for wind generation) described in Table 3.1. For each quality of wind, there are five different levels of wind penetration summarized in Table 4.1. This implies that 15 different scenarios are evaluated for each configuration of the network. The network in Figure 3.1 consists of three zones or areas. Area 1 represents an urban area with relatively expensive generating units, and Area 2 and Area 3 represent two rural areas with relatively inexpensive generating units, including wind turbines in Area 2. There are three tie lines (Line 12, Line 14, and Line 36) connecting Area 1 to Area 3, one tie line (Line 15) connecting Area 1 to Area 2, and two tie lines (Line 25 and Line 36)[24] connecting Area 2 and Area 3. In total, there are 39 lines in the network, and modifications to the network that are used in the analysis were selected to illustrate effects of changing the capacity of three different types of transmission line.

Before performing any modification of the network, no network constraints [25] are implemented, to reassure that there are no anomalies involving network constraints in this case study. The first modification of the network changes the capacity of the best representative of a tie line (Line 15, the primary transmission line linking the urban center in Area 1 to wind generators in Area 2). The main contribution of this type of transmission line is to transfer inexpensive energy to the urban center. With high levels of wind capacity installed, congestion on this tie line limits the amount of potential wind generation that can be dispatched, and changing the capacity of Line 15 affects how often congestion occurs.

[24] Tie Line 26, connecting Area 2 to Area 3, has been removed from the network for these simulations.
[25] No network constraints in this simulation have been achieved by setting thermal limits in each transmission line in the system to zero (infinite line capacity) and resistance to zero (no losses).

The second modification changes the capacity of Line 22 in Area 2, which is an example of a line in a meshed network that is often congested. Results in Figure 4.3 show that congestion revenues for Line 22 are large, but its main distinguishing feature is that it is the best example of a line that is important for maintaining reliability. The final modification changes the capacity of Line 7 in Area 1. This is another example of a line in a meshed network. However, Line 7 is not like Line 22, because results in Figure 4.3 show that congestion revenues for this line are relatively small and generally negative. Line 7 is generally redundant from the system point of view, although it may be important for maintaining reliability in some scenarios.

Specific configurations of the network that are evaluated are:

1. Eliminate network constraints shown in Figure 3.1.
2. Initial network topology shown in Figure 3.1.
3. Upgrade Line 15 by +100%
4. Downgrade Line 7 by -25%
5. Downgrade Line 15 by -25%
6. Downgrade Line 22 by -25%

For each of these configurations, 15 scenarios are evaluated for the three different types of wind quality and the five different levels of wind penetration. For each scenario, the Total Annual System Cost is the sum over the 100 load levels using three different forecasts of wind speed shown in Table 3.1 for each load level.[26] Comparing Total Annual System Costs for any one of the 15 scenarios using the initial unmodified network with the corresponding scenario with one of the modified networks measures the net economic benefit of making the modification.

[26] For each combination of load level and wind forecast, the expected operating cost is computed for the 19 different intact and contingency cases shown in Table 4.3.

4.5.3 Comparing Total Annual System Costs for Different Scenarios

Before discussing empirical results, it is important to reiterate two important qualifications that govern this analysis. First, the network is relatively small, and, as a result, effects of congestion are more pronounced than they would be on a larger network. Second, characteristics of wind generation are extreme. At the highest level of wind penetration (105MW for Level 4), wind capacity comprises roughly one quarter of all installed capacity and can provide roughly half of total annual generation. Furthermore, all wind capacity is located at a single node so that there is no geographic smoothing of the total potential amount of wind generation. In addition, probability of having the turbines cut out with high wind speeds is high (14% in Table 3.1). In reality, individual turbines in a wind farm do not cut out at exactly the same time.

The Total Annual System Cost paid by customers consists of total annual payments for purchasing electricity in the wholesale market plus additional money paid to generators and transmission owners. It is assumed for all scenarios that transmission owners receive a total of $30 million/year to cover all costs for the existing network including annualized capital costs. Part of this total is paid by congestion rents in the wholesale market, and the remaining part is additional money. For scenarios in which the system operator pays out more to generators than the amount received from customers, congestion rents are negative and the corresponding amount of additional money will be larger than $30 million/year. Customers still end up paying the same total cost for transmission because some additional money is used to make the system operator financially whole.

For generators, the situation is more complicated because the amount of conventional generating capacity needed for System Adequacy and total annual operating costs vary from scenario to scenario. Nevertheless, the total annualized capital cost of conventional generating units is paid in a similar way to that for payments for transmission. Some of the money comes from earnings in the wholesale market and the rest is paid through a Capacity Market.[27]

Figures 4.4-4.6 summarize overall results of the analysis for the three different qualities of wind by showing the composition of the Total Annual Systems Costs for the different scenarios.[28] The first three components (the lowest three) are Operating Costs, Generator Net Revenues and Wind Net Revenues. The sum of these three components represents payments made to generators in the wholesale market for energy and ancillary services. The large reductions in these payments when wind capacity is added with NORMAL Wind and NICE Wind are obvious. Reductions come from displacement of some conventional generation by wind generation with corresponding reductions in wholesale prices. However, reductions in Operating Costs for NORMAL Wind are relatively small as more wind capacity is added, compared to reductions for NICE Wind because more potential wind generation is spilled.

Results for NASTY Wind shown in Figure 4.6 are very different. Comparing the first level of wind (Level 1) with no wind (Level 0) shows that payments to generators are lower, but, with higher penetration levels, payments increase. This happens because it is expensive to spill NASTY Wind, but it is also expensive for the network to accommodate more wind generation, and, in particular, congestion is more serious. Even though less potential wind generation is spilled, Operating Costs actually increase with higher levels of wind penetration because it is necessary to dispatch

[27] See the detail calculation in Chapter 3, Section 3.5

[28] Note that values for NO wind (Level 0) are identical to those for NORMAL, NICE and NASTY Wind, given a particular network configuration.

more expensive peaking units to balance flows on the network. In addition, Net Earnings of conventional generators also increases with more wind even though the amount that they generate is lower because wholesale prices are higher.

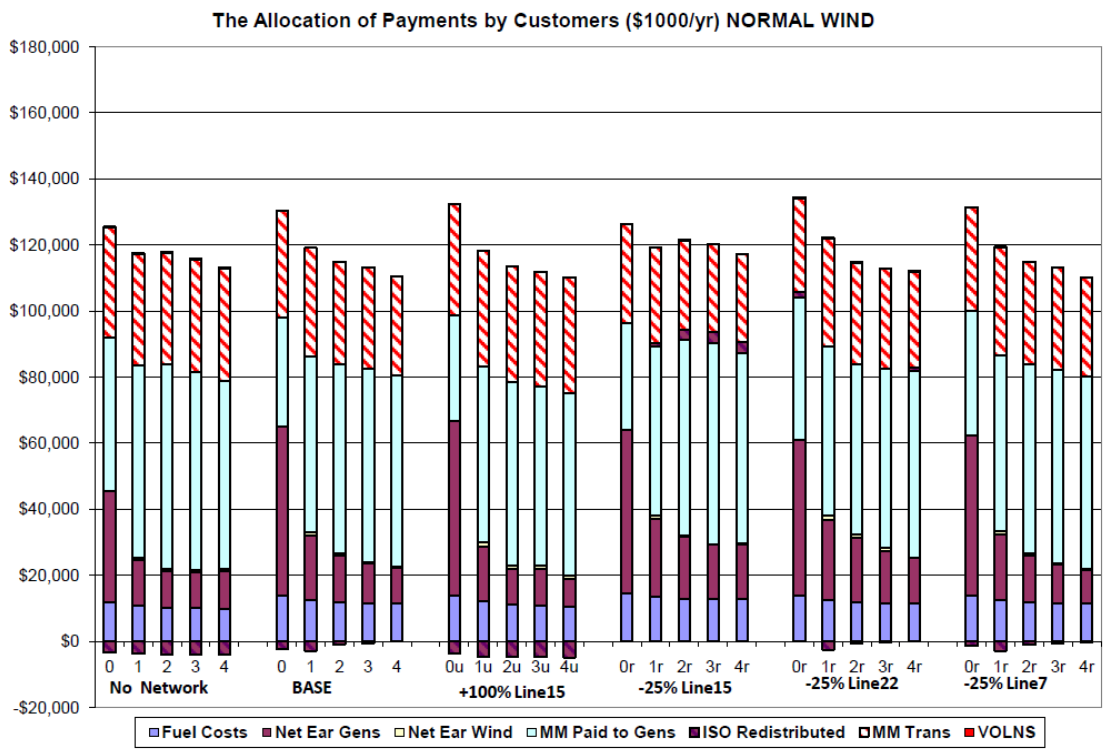

Figure 4.4: Total Annual System Costs Paid by Customers for NORMAL Wind

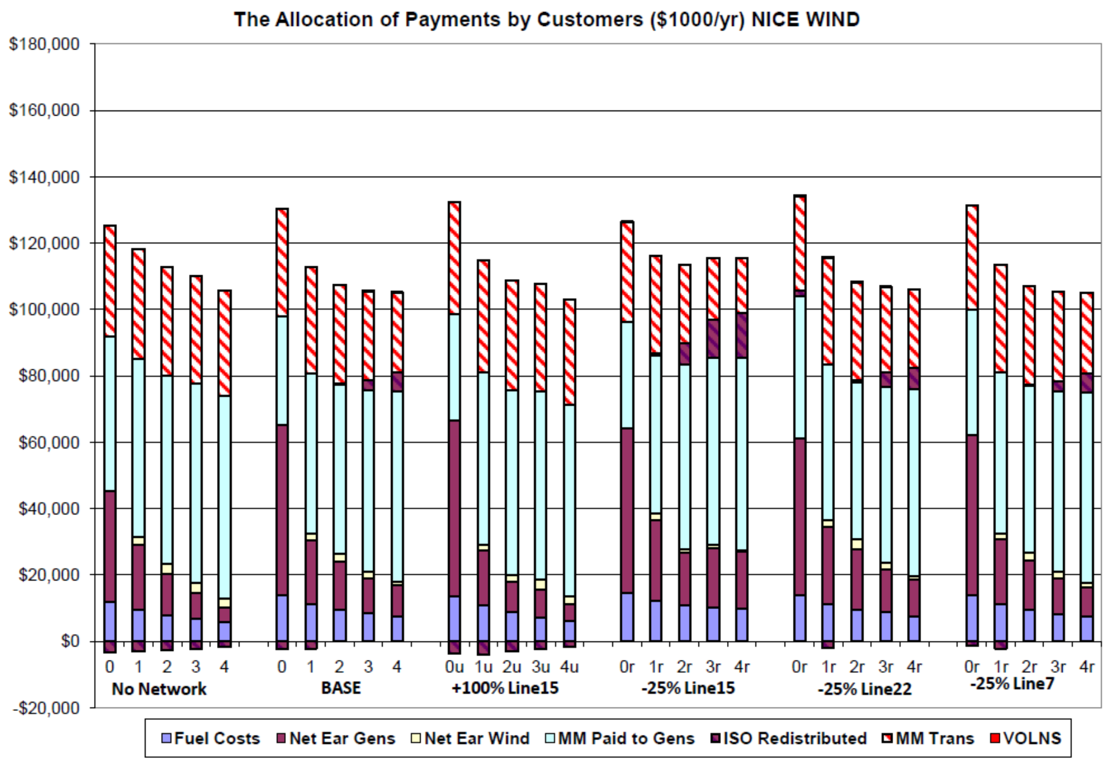

Figure 4.5: Total Annual System Costs Paid by Customers for NICE Wind

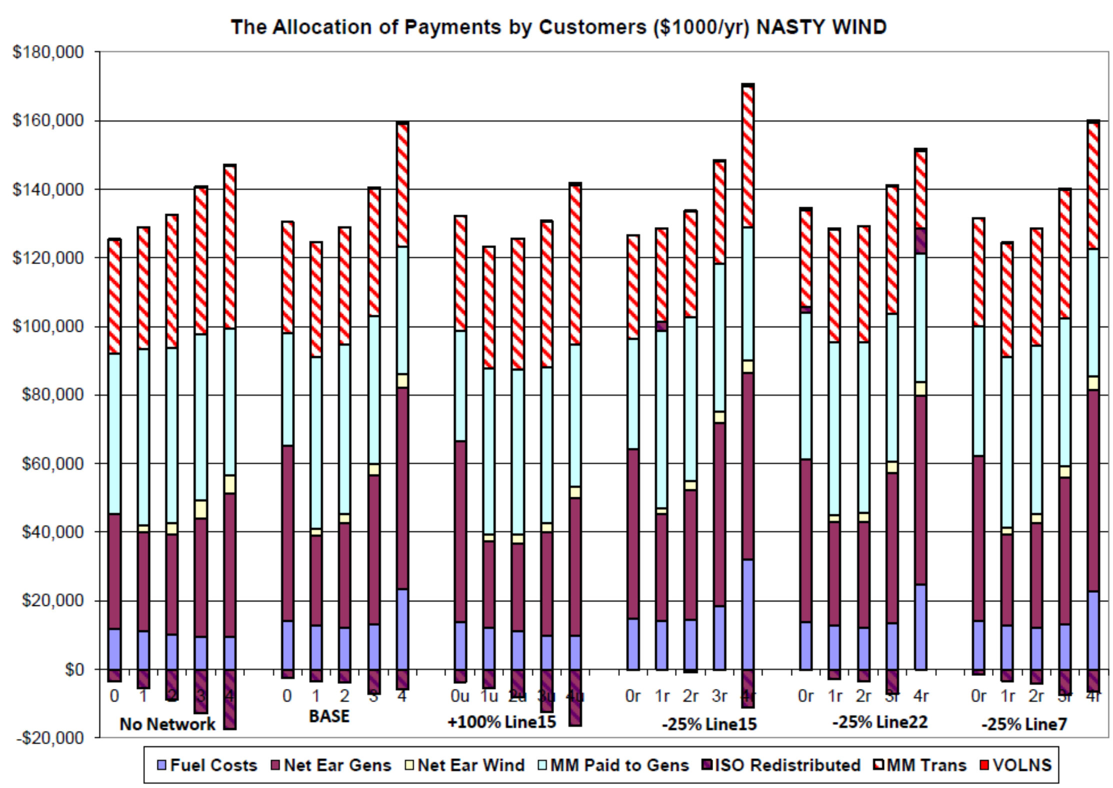

Figure 4.6: Total Annual System Costs Paid by Customers for NASTY Wind

For all scenarios, Net Earnings of wind generators in the wholesale market are very small compared with payments made for the conventional generators, particularly for NORMAL Wind. Net Earnings of wind generators are slightly higher for NICE Wind, because more wind generation is dispatched, and even higher for NASTY Wind because of the combination of higher wholesale prices and dispatching more wind generation.

Substantial reductions in the annual wholesale payments for high penetrations of NORMAL Wind shown in Figure 4.4 are largely offset by the large increase in the capacity payments made to conventional generators to maintain their Financial Adequacy. Corresponding capacity payments are lower for NICE Wind because less generating capacity is needed to maintain System Adequacy, and, as a result, the Total Annual System Cost is also lower.[29] Coupling wind generation with storage, batteries are charged when wind speeds are high and discharged when wind speeds are low. This reduces the range of net generation from the wind farm substantially and also reduces the uncertainty of net potential generation for a given forecast of wind speed. In contrast, for NASTY Wind, high payments in the wholesale market and need for more installed conventional generating capacity to maintain System Adequacy cause the Total Annual System Cost to increase with higher levels of wind penetration.

The main conclusion at this point is to reaffirm that focusing on reductions in the average wholesale price when wind capacity is introduced into a deregulated market can be misleading. When determining net benefits of adding wind capacity to a network, regulators should also consider effects on inadequate earnings needed by conventional generators and transmission owners to maintain their Financial Adequacy.

[29] Total payments made to transmission owners are the same in all scenarios.

4.5.4 Financial Effects of Modifying Network Configuration

Turning now to evaluating effects of making modifications to the network, the difference in Total Annual System Costs for each level of wind penetration for a modified network compared to the initial network configuration are shown in Figures 4.7-4.9 for the four different modifications made to the network. Since Lines 15 and 22 both earn large positive congestion revenues in Figure 4.3, one would expect that, in general, upgrading Line 15 will reduce Total Annual System Costs (i.e. have positive savings) and downgrading Line 15 or Line 22 will increase the Total Annual System Cost (i.e. have negative savings). Since congestion revenues for Line 7 are relatively small, it is less clear what expected effects of downgrading this line will be. Actual results are, however, much more complicated and differ markedly for NORMAL, NICE and NASTY Wind.

The results closest to prior expectations are exhibited by NASTY Wind when Line 15 is modified (Figure 4.9). This tie line is the main transmission link between the wind farm and the urban center. Since NASTY Wind represents must-take contracts for wind generation, benefits from upgrading (downgrading) the capacity of Line 15 increase (decrease) when penetration of wind increases. For NORMAL Wind (Levels 1-4), signs of savings when Line 15 is modified are consistent with prior expectations. However, savings do not change consistently with the level of penetration and magnitudes of savings are relatively moderate compared to corresponding savings with NASTY Wind.

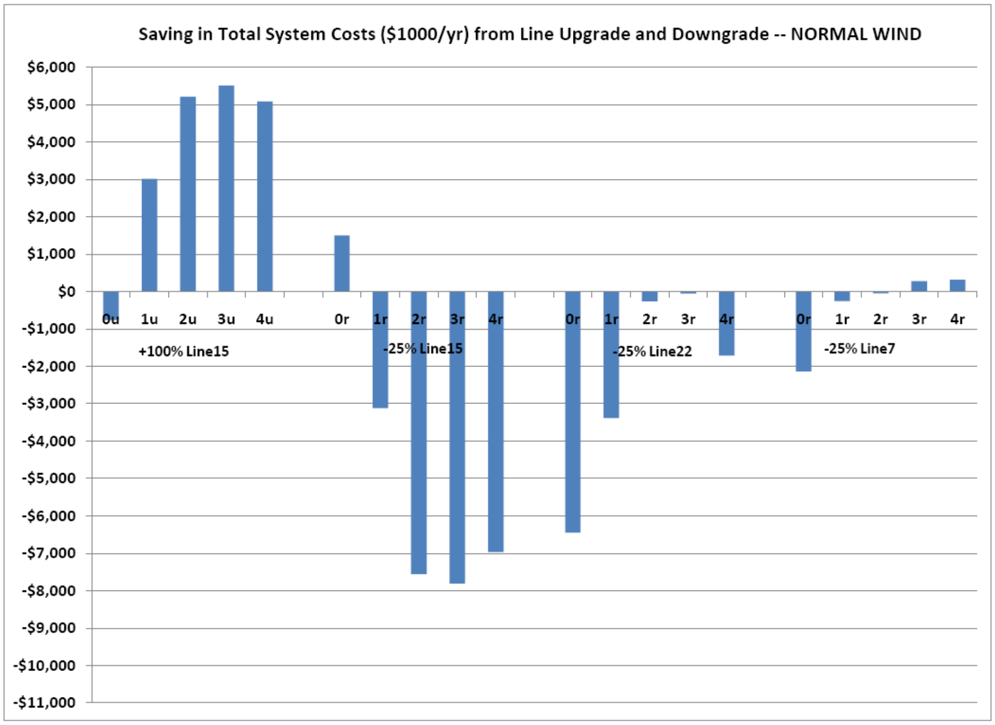

Figure 4.7: Saving in Total Annual System Costs ($1000/yr) for NORMAL Wind

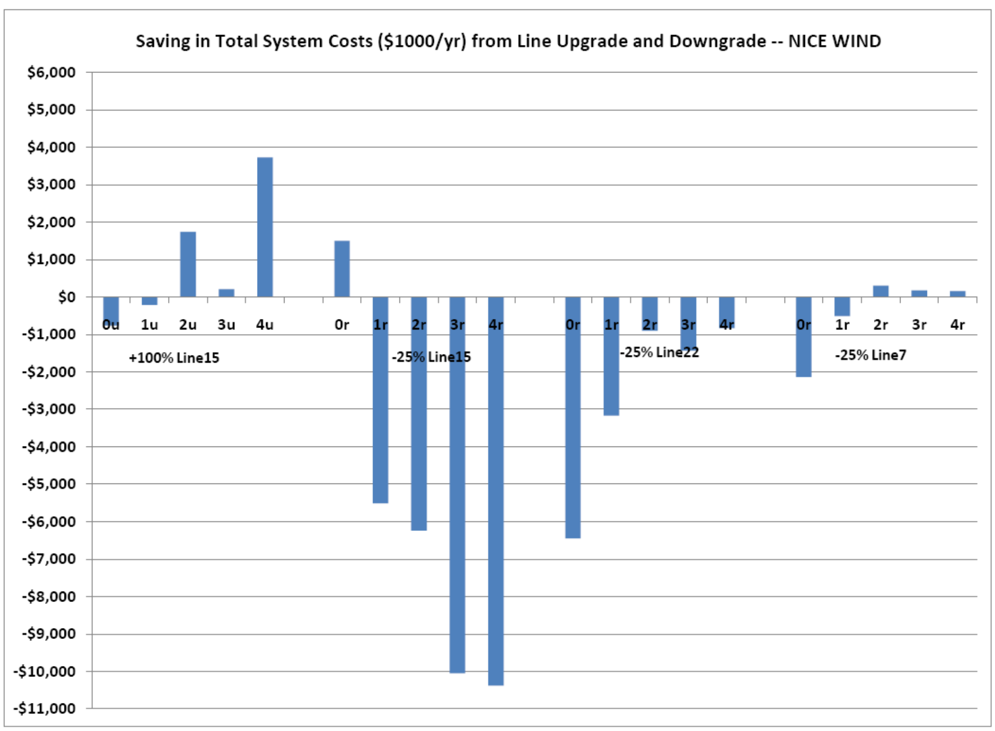

Figure 4.8: Savings in Total Annual System Costs ($1000/yr) for NICE Wind

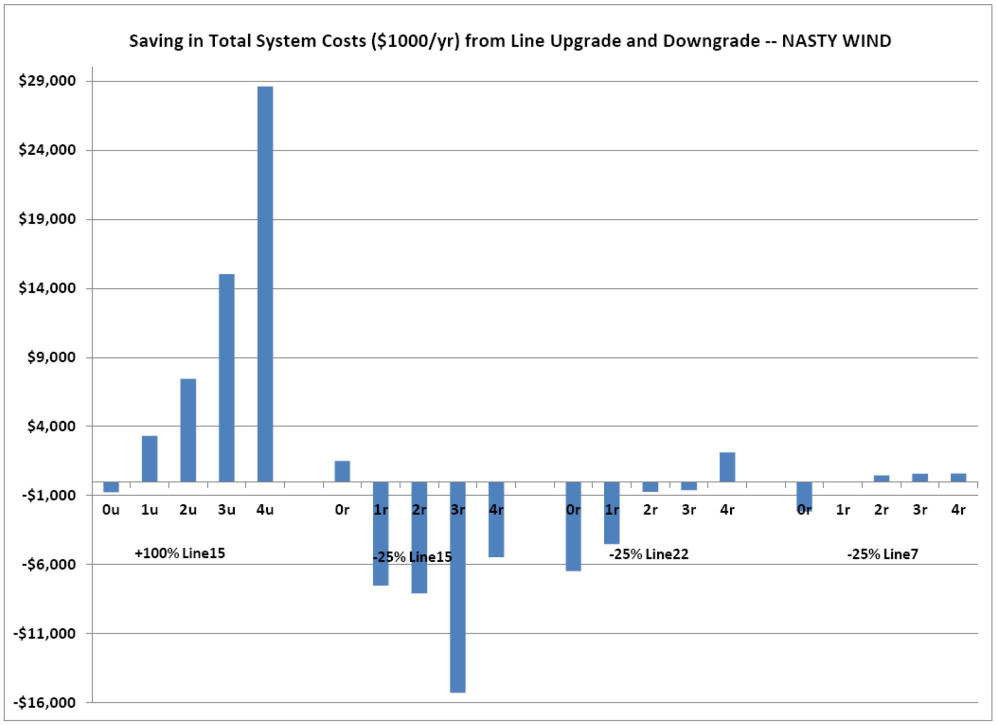

Figure 4.9: Savings in Total Annual System Costs ($1000/yr) for NASTY Wind

The most surprising result when Line 15 is modified is for NICE Wind (Levels 1-4) because Total Annual System Costs increase (i.e. negative savings) and also decrease (i.e. positive savings) depending on wind penetration levels when the line is upgraded. However, when it is downgraded, results are closest to prior expectations. Coupling wind generation with storage is effectively an alternative way to use more potential wind generation without upgrading Line 15. Upgrading the capacity of Line 15 matters most for NASTY Wind when wind generation is forced on the network through must-take contracts. For NORMAL Wind, benefits of upgrading Line 15 are relatively moderate, and, for NICE Wind, the upgrade reduces and/or increases system benefits depending on wind penetration levels.

Savings from downgrading Line 22, the line that is important for reliability, are generally negative as expected (only positive in one case, NASTY Wind Level 4) . However, there are no clear trends in the magnitudes of losses as levels of wind penetration increase, and there is no consistent explanation for why levels of savings vary this way. These explanations tend to be very idiosyncratic and are influenced by the relative importance of different binding constraints in the each scenario. There is only one notable anomaly: positive savings for NASTY Wind with the highest level of wind penetration (Level 4). The main reason for this unusual result is that t congestion rents collected by the system operator are negative with the initial network and positive when Line 22 is downgraded. As a result, additional money paid to transmission owners is reduced substantially when Line 22 is downgraded.

Downgrading Line 7, the potentially redundant line, does increase Total Annual System Costs (i.e. negative savings) in the no wind (Level 0) case, as expected, and, with higher levels of wind penetration, levels of savings are all close to zero regardless of which quality of wind is specified. The overall conclusion about economic benefits of modifying individual transmission lines in the network is that the direction of the net system benefit from a specific modification is difficult to predict, and, furthermore, the magnitude is very sensitive to the amount and quality of the wind resource. The only example that is generally consistent with economic intuition is when the capacity of a major tie line (Line 15) is changed and the system operator is required to dispatch all potential wind generation (i.e. with NASTY Wind).

4.5.5 Composition of Aggregate Annual Congestion Revenues

To complete the empirical analysis, compositions of Aggregate Annual Congestion Revenues for the network are reported for different scenarios discussed in the previous sub-section. A description of how to compute Expected Annual Congestion Revenues for individual transmission lines is presented in Section 4.4.1 for one scenario (Table 4.5 and Figure 4.3). This description also explains how these revenues can be separated into 1) a part representing transfer of energy (intact cases 0-3 in Table 4.3), and 2) a part representing maintenance of reliability (contingency cases 4-18 in Table 4.3).

Expected Annual Congestion Revenue measures the standard way that the economic value of a transmission line is measured in economics textbooks (energy flows times the corresponding differences in nodal prices) and, also, the way that the owner of a Financial Transfer Right for a single transmission line would be paid. However, it is important to remember that these revenues are not the same as actual congestion rents collected (ISO Redistributed) by system operators in a wholesale market (total payments received from customers minus total payments made to generators), and, in addition, Expected Annual Congestion Revenues do not consider any of the additional money paid to transmission owners. For example, in the Nice wind upgraded tie line case, Expected Annual Congestion Revenues decrease as the wind penetration level increases ($7,283/year in the lowest levels of wind penetration to $1,213/year in the highest levels of wind penetration). However, the ISO Redistributed is a negative number and increases as the wind penetration levels increases (-$3,651/year in the lowest levels of wind penetration to -$1,638/year in the highest levels of wind penetration). This implies that system operators will first pay the difference and then charge back to customers' bills. The correct way to determine the economic value of transmission is by evaluating the Total Annual System Cost shown in Figures 4.4-4.6. Since total annual payments for transmission are the same in every scenario, changes in Aggregate Annual Congestion Revenues do not affect changes in Total Annual System Costs.

Figures 4.10-4.12 show Aggregate Annual Congestion Revenues for the three different qualities of wind. The value for each scenario is the summation of Expected Annual Congestion Revenues for the 39 transmission lines, and this total is divided into a reliability part (Contingency, red stripes) and a transfer part (Intact, solid blue). In general, revenues for reliability are much smaller than revenues for transfers. However, this is not the case when Line 15 is upgraded (the main tie line linking the wind farm to the urban center) because there is much less congestion in these scenarios, and, as a result, nodal price differences for the intact network are small, and, in fact, two of the transfer revenues in Figure 12 are negative for NASTY Wind.[30] When Line 15 is downgraded, Aggregate Annual Congestion Revenues for transfers are substantially larger than the revenues for reliability, as expected, because there is more congestion.

Another general feature of Figures 4.10-4.12 is that higher levels of wind penetration for a given network configuration lead to lower revenues for reliability and to higher revenues for transfers. More wind generation is dispatched on the intact network are generally higher for higher levels of wind penetration and this leads to higher revenues for transfers. In addition, congestion occurs more frequently, implying that nodal price differences are higher. However, it is surprising that revenues for reliability decrease with higher wind penetration. The basic explanation for this is that "perverse" nodal price differences (i.e. negative congestion revenues) occur more often, and this reduces Aggregate Annual Congestion Revenues.

[30] The Congestion Revenues can be positive under some conditions and negative for others (see Section 4.4).

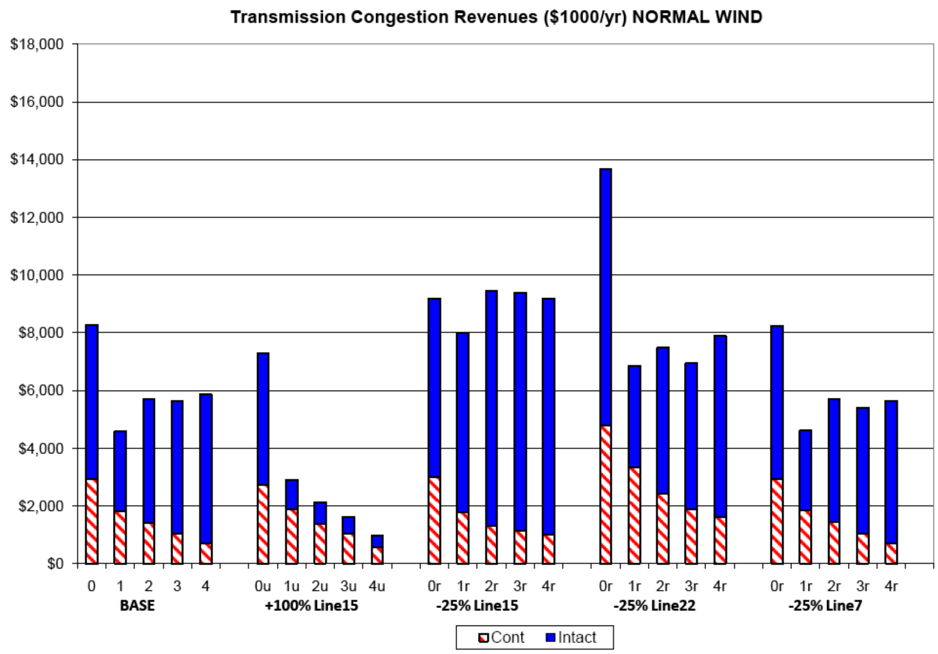

Figure 4.10: Annual Congestion Revenues ($1000/yr) for NORMAL Wind

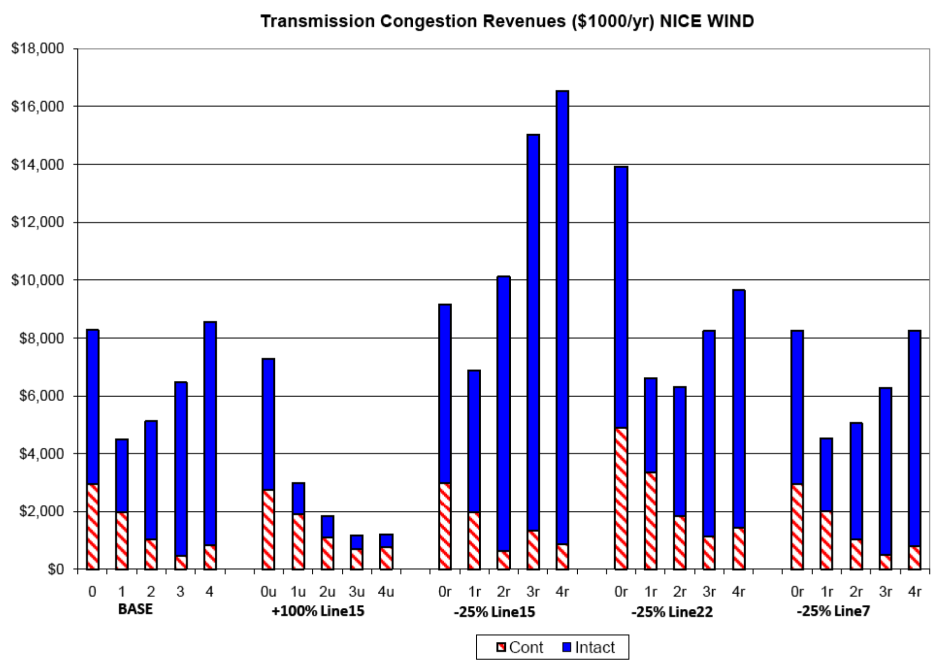

Figure 4.11: Annual Congestion Revenues ($1000/yr) for NICE Wind

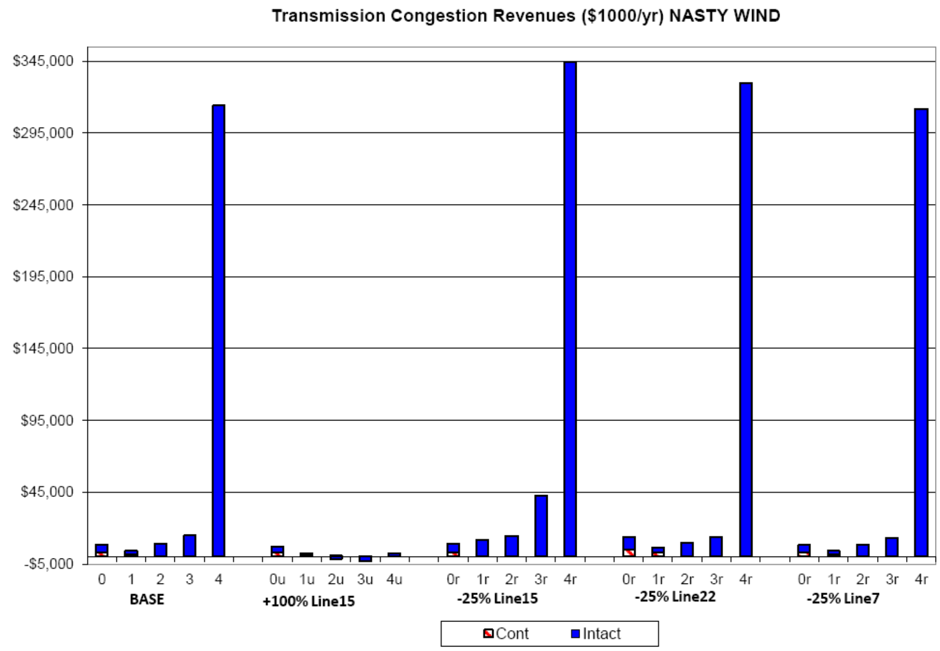

Figure 4.12: Annual Congestion Revenues ($1000/yr) for NASTY Wind

For NORMAL Wind, revenues for transfers tend to stabilize for levels of wind penetration above Level 2 because most additional potential wind generation is spilled. For NICE Wind, it is economical to use more potential wind generation, and less wind is spilled, and, for NASTY WIND, almost all potential wind generation is dispatched because this is a requirement of a must-take contract. This must-take requirement has dramatic effects in terms of increasing transfer revenues for the highest level of wind penetration (Level 4) on four of the five network configurations. The exception to this is when the capacity of Line 15 is upgraded, because the congestion on this network is reduced substantially. The highest Aggregate Annual Congestion Revenue for NASTY Wind is over $300,000/year, compared to less than $17,000/year for NORMAL and NICE Wind. The reason for the exceptionally high value for Level 4 with NASTY Wind is that a substantial amount of load shedding occurs, and, when load is shed at a node, the nodal price is equal to the VOLL (VOLL = $5,000/MWh in Areas 2 and 3, and $10,000/MWh in Area 1)[31].

4.6. Summary and Conclusion

Many regulators believe that the size of congestion revenues (flow of energy times the nodal price difference) provides correct incentives for investing in new transmission lines in deregulated markets for electricity. This rationale for merchant transmission is potentially feasible in some cases, for transmission lines that are needed mainly for transferring energy from inexpensive sources to expensive sinks, e.g. transmission lines linking hydropower in Quebec to customers in Boston and New York City. However, maintaining Operating Reliability (i.e. providing redundant capacity to avoid shedding load when equipment failures/contingencies occur) is also an important function of transmission. In a meshed AC network, a single transmission line may play an essential role in maintaining reliability of supply as well as in transferring power. Since reliability is essentially a public good, merchant transmission owners will tend to under-invest in transmission lines needed for reliability purposes. In practice, many transmission upgrades are justified on the basis of reliability, and so are eligible for payments using standard regulatory procedures.

The SuperOPF determines both the optimum dispatch and optimum pattern of reserve generating capacity by minimizing the expected cost of meeting load over an explicit set of credible contingencies. Corresponding nodal prices reflect patterns of dispatch for the intact system as well as for the system when contingencies/failures occur. The main difference between this criterion and the criterion in a standard

[31] Although the VOLL is technically the correct market price, customers would not pay this price in practice, because the system operator would overrule the market solution.

Security Constrained OPF is that shedding load at a very high cost is allowed in the SuperOPF. Endogenous amounts of generating capacity committed for dispatch and reserves to meet the same peak system load in different scenarios can vary substantially, and these different amounts of capacity define requirements for maintaining System Adequacy for a given network. In contrast, capacities of transmission lines remain the same in different scenarios and for different levels of load unless an explicit modification is made.

Probabilities of contingencies occurring are small, but corresponding nodal prices may be high enough to provide a major source of revenue for generators and transmission owners. Although the cost of purchasing reserve capacity represents the direct operating cost of maintaining reliability for generators, there is no simple equivalent for determining the cost of maintaining reliability for transmission. This chapter uses the SuperOPF to distinguish between congestion revenues for 1) transferring energy, and 2) maintaining the reliability of a network. Its main contribution is to show that determining the net benefit of a transmission line is much more complicated than the standard representation in economics textbooks. In fact, the net economic benefit of upgrading a transmission line, for example, should be measured by reduction in the Total Annual System Cost, including additional money for maintaining Financial Adequacy and the cost of Load-Not-Served. Using the corresponding reduction in congestion revenues for a transmission line as the measure of net benefit may be very misleading.

When new wind capacity is added to a network, economic effects are very sensitive to how effectively the inherent variability of wind generation is accommodated. With higher penetrations of wind generation, it will be even more impractical to rely on conventional economic incentives to develop an effective investment plan for transmission that maintains reliability standards. When this analysis was initiated, the expectation was that it would be fairly straightforward to interpret the relationship between the level of wind penetration and the corresponding congestion revenues. Unfortunately, it turned out that this was not the case. The underlying problem is that congestion revenues for individual transmission lines can be negative in some situations and positive in others. This phenomenon is caused by inflexibility of transmission capacities, and illustrates why determining an optimal network configuration is such a challenging problem. The same network must operate over a wide range of different conditions (e.g. levels of load)[32]. In addition, modifying the capacity of transmission lines will have direct effects on earnings of generators as well as transmission owners.

The first objective of the analysis is to determine the amount of transmission congestion revenues coming from: 1) transferring energy, and 2) maintaining reliability. Procedures used to meet this objective are described in Section 4.4, and compositions of Aggregate Annual Congestion Revenues for the network are reported for the different scenarios in Section 4.5. The example presented in Section 4.4 for a 30-bus test network shows that two transmission lines have substantially larger congestion revenues than the others. One is an example of a tie line that is needed primarily for transferring energy from the wind farm to the urban center (Line 15) and the other is a line embedded in a meshed network that is mainly needed for maintaining reliability (Line 22). This example also shows that ranges of realized nodal price differences for different contingencies are generally much larger for individual transmission lines than corresponding ranges for the intact network. However, the small probabilities for the contingencies make the aggregate for the

[32] The addition of Flexible AC Transmission Systems (FACTS) promises to alleviate this problem, to some extent.

network of the Expected Annual Congestion Revenues for reliability smaller than the corresponding value for transferring energy.

The scenarios presented in Section 4.5 evaluate three different qualities of wind (NORMAL, NICE, and NASTY) and five different levels of wind penetration for each quality, ranging from zero to roughly one quarter of installed generating capacity. In addition, four modifications of the network are considered. These are 1) upgrading a tie line needed for transferring energy (Line 15), 2) downgrading a potentially redundant line (Line 7), 3) downgrading Line 15, and 4) downgrading a line needed mainly for reliability (Line 22).

Using the initial network configuration, higher penetrations of NORMAL Wind lead to reductions of payments in the wholesale market, but these are largely offset by higher payments of additional money to conventional generators. Net benefits tend to stabilize for higher levels of wind penetration because most additional potential wind generation is spilled. For NICE Wind, it is economical to use more potential wind generation; less wind is spilled, and, in addition, net benefits increase more, because less conventional generating capacity is needed to maintain System Adequacy. For NASTY Wind, almost all potential wind generation is dispatched, because this is a requirement of a must-take contract. However, payments in the wholesale market increase substantially because it is necessary to use more of the expensive peaking capacity to maintain Operating Reliability, and more conventional generating capacity is needed to maintain System Adequacy.

When comparing changes in Total Annual System Costs after modifying the network, the only modifications that are clearly consistent with standard economic expectations are changing the capacity of the tie line (Line 15) with must-take contracts for wind generation (NASTY Wind). System benefits increase (decrease) proportionally with higher levels of wind penetration when Line 15 is upgraded (downgraded). For other network modifications, changes in net benefits are not as consistent with the level of wind penetration and explanations for specific cases are more idiosyncratic. In general, net benefits from upgrading Line 15 are smaller for NORMAL Wind than for NASTY Wind. For NICE Wind, net benefits are smallest, because using storage to limit the range of potential net generation from the wind farm is an effective substitute for adding transmission capacity to Line 15.

The overall conclusion is that transmission networks, as compared to point to point links like D.C. lines, should remain regulated because of the importance of public good features for maintaining reliability. Although there may be situations in which reductions in congestion revenues for a specific transmission line can be used to justify an upgrade, upgrading transmission lines will generally have implications for the economic cost of meeting reliability standards that should not be ignored. These reliability effects can reduce operating costs of meeting standards of Operating Reliability by avoiding load shedding, and can also reduce the amount of conventional generating capacity needed to maintain System Adequacy and associated payments of additional money. Consequently, it may be very misleading to rely on estimated reductions in total congestion revenues for a transmission line to justify investing in an upgrade. Some form of planning process is needed to ensure that there really are net benefits for the network from an investment and that reliability standards are maintained.

(Toomey, Schulze et al. 2005) conducted an economic analysis of an electricity supply system, paying particular attention to physical constraints. His model includes electrical equipment constraints such as generator limits and line flow limits, and also network constraints i.e., Kirchhoff's laws. Toomey's analysis shows that, most of the time, when the system is intact, the value of transmission lines is virtually zero. However, when low probability contingencies occur, transmission lines are very valuable. In other words, congestion revenues do not provide a viable source of income for transmission lines when the system is intact. The income is realized for maintaining reliability on a network. The conclusions from this chapter differ from Toomey's conclusions. The explanation is that the economic analysis in Toomey's paper imposes no Price Cap (equivalent to an energy-only market). This allows, when contingencies occur, prices to go as high as the VOLL. It reflects the net economic benefits of maintaining System Adequacy for those transmission lines. However, the analysis presented here in Chapter 4 represents a deregulated market with a Price Cap and because offers to sell in the wholesale market are set equal to the marginal costs (i.e. no speculation occurs). With this type of wholesale market, payments made by customers must include some additional form of Capacity Compensation as the cost of maintaining System Adequacy, and in the Northeast US, capacity markets are used to support generators adequacy.

CHAPTER 5

SUMMARY AND CONCLUSIONS

The goal of this dissertation is to present an analytical framework that determines the economic value of both operating reliability and system adequacy in a mutually consistent way. Chapter 2 presents the general characteristics of how the SuperOPF can be used to achieve this goal. Important features of the SuperOPF are 1) contingencies are considered explicitly in the optimization, 2) load shedding at a high VOLL is allowed in all contingencies, and 3) the optimization incorporates the nonlinear constraints of a full AC network. These three features make it possible to 1) determine correct shadow prices for different components of the network under different operating conditions, 2) calculate the correct net social benefit of maintaining Operating Reliability, and 3) evaluate the net economic benefit of relying more on intermittent sources of generation, such as wind capacity, that lower production costs but increase the costs of ancillary services needed to maintain reliability. In contrast, system operators typically determine an “optimum” dispatch for an intact system and comply with operating reliability indirectly by adding physical proxy constraints, such as setting fixed minimum levels of locational reserve generating capacity, specifying “proxy limits” on real power flows allowed on specific transmission lines. Corresponding nodal prices are highly misleading, particularly when the system is stressed, but these are precisely the prices that must be determined correctly to measure economic value of reliability. In particular, benefits of some equipment are only realized when contingencies occur.

In Chapter 3, case studies are used to illustrate how the SuperOPF can be extended to evaluate system adequacy when adding wind capacity to a network. Many studies in the electricity market focus only on lower operating costs in a wholesale market when adding wind capacity. However, cost of maintaining System Adequacy includes both money paid in markets for energy and operating reserves and in some regions where markets are used to select and compensate generation through some form of Capacity Market. Hence, simply focusing on lower operating costs in a wholesale market is inadequate. The SuperOPF determines the amount of conventional generating capacity needed to maintain Operating Reliability endogenously. Consequently, it is possible to determine net social benefits of relying more on adding wind capacity. This feature provides a consistent economic framework for evaluating Operating Reliability in real-time markets and System Adequacy for planning purposes. A financially viable investment requires that reductions in total annual costs of the existing system should be larger than the annualized cost of financing the addition of, for example, wind generation to a network.

The scenarios considered in Chapter 3 make it possible to determine: 1) the amount of conventional generating capacity needed to meet the peak system load and maintain System Adequacy, 2) the amount of money paid to needed generators to maintain their Financial Adequacy, 3) changes in congestion rents for transmission collected by the system operator, and, finally, 4) total annual system costs paid by customers directly in the Wholesale Market and, indirectly, through guarantee payments and subsidies. The results show that benefits (i.e. reduction in total annual system costs) from making an investment in wind capacity and/or upgrading a tie line are very sensitive to 1) how much inherent variability of wind generation has to be accommodated on the network, and 2) how the amount of money required for the Financial Adequacy of conventional generators is determined (e.g. comparing a regulated allocation and a deregulated market for wholesale exchanges of power). For planning purposes, it is essential to consider Financial Adequacy of conventional generators as well as wholesale prices when evaluating economic net benefits of adding wind capacity to and/or upgrading transmission for a network.

In Chapter 4, an analytical framework for determining the economic value of individual transmission lines is presented to determine, in particular, how these economic values change when adding wind capacity to a network. The conventional economists' view of transmission lines in a network is that they are there for transferring electricity from inexpensive sources to expensive sinks. This concept works reasonably well when the topology of a network is radial. However, when the topology is meshed, this conventional representation falls apart. In a meshed network, there are multiple ways that electricity can flow from a specific source to a specific sink, and these flows do not necessarily respect market logic, because they are governed by the laws of physics. The redundancy of multiple pathways between sources and sinks in a meshed network is nothing new from the point of view of system operators. These redundancies are important for maintaining the reliability of supply. This implies that there is another level of complexity for economists to consider when determining costs and benefits of transmission lines. Hence, the conventional manner of valuing the transmission lines is inadequate. Using the SuperOPF, it is possible to distinguish between congestion revenues (flow of energy times nodal price difference) for 1) transferring energy and 2) maintaining reliability of a network. The analysis also determines how these costs change when: 1) different levels of wind capacity and different qualities of wind capacity are installed at a remote location, and 2) changes are made to the capacity of selected transmission lines.

The results show that the net benefits (i.e. changes in total annual system costs, including capital costs and expected cost of Load-Not-Served) and relative magnitudes of congestion rents for transfers and for reliability are very sensitive to how effectively the inherent variability of wind generation is accommodated on the network. With higher penetrations of wind generation, it becomes even more impractical to rely on the changes in congestion revenues to develop an efficient investment plan for transmission that maintains reliability standards. The main conclusion for regulators is that evaluating the contribution of transmission lines in a meshed network should consider combined benefits from: 1) transferring real energy, 2) maintaining reliability standards, and 3) any additional money needed to ensure Financial Adequacy of owners of both transmission and generation.

The overall conclusions of this dissertation have important implications for regulators in states with a deregulated market. The general form of the annual cost of supplying a customer with electricity can be written as follows:

Annual Cost = a + b x Energy + c x Capacity

where **a** is the costs of billing a customer,

b is the average wholesale price of energy,

c is the average price of capacity.

Currently, regulators can measure **a**, **b,** and **Energy** relatively well, although there is still some controversy about whether or not wholesale prices, **b**, observed in a market are really competitive. The main deficiency is in the measurement of **c** and **Capacity**. Determining the appropriate value of **c** is handicapped by uncertainty about actual Operating Costs and Capital Costs of generators, and measuring **Capacity** is also limited by the type of meter installed.

As shown in Chapters 3 and 4, the amount of conventional generating capacity needed for System Adequacy can vary substantially with different assumptions about characteristics of wind generation. Furthermore, high levels of wind penetration on a network will tend to lower the wholesale price, **b**, and as a result, lower earnings of conventional generating units. The price of capacity, **c**, must increase if the Financial Adequacy of these generating units is to be maintained. At the present time, concerns of analysts and regulators have focused on the performance of deregulated wholesale markets. Far too little attention has been paid to determining the amount of additional money really needed for System Adequacy. Financial Adequacy should be recognized as an important criterion for maintaining reliability of supply, and regulators should spend a lot more effort collecting information needed to measure legitimate levels of money required by generators and transmission owners to repair, replace and finance their facilities. Once these accurate measurements are available, it will be feasible to restructure rates charged to customers so that they provide correct net economic benefits that reflect true system costs.

Most retail customers currently pay fixed rates for energy and some lump-sum charges in their electricity bills to cover other costs. Therefore, they do not experience real-time pricing charges, and in addition, they do not pay explicitly for their share of the installed capacity needed for System Adequacy. The case studies in this dissertation imply that there is an untapped opportunity for demand-side management to reduce the system peak load. For example, an aggregate of customers' demands could be formed and, with controllable demand, used to shift load from peak to off-peak periods. This would reduce the physical amount of generating capacity needed for System Adequacy. Figure 5.1 illustrates the effect of shifting demand on the load duration curves used in Chapters 3 and 4 by flattening the daily load patterns. The modified load duration curves reduce the system peak on average by about 24% (26% for New York City and Long Island, and 22% for Upstate New York).

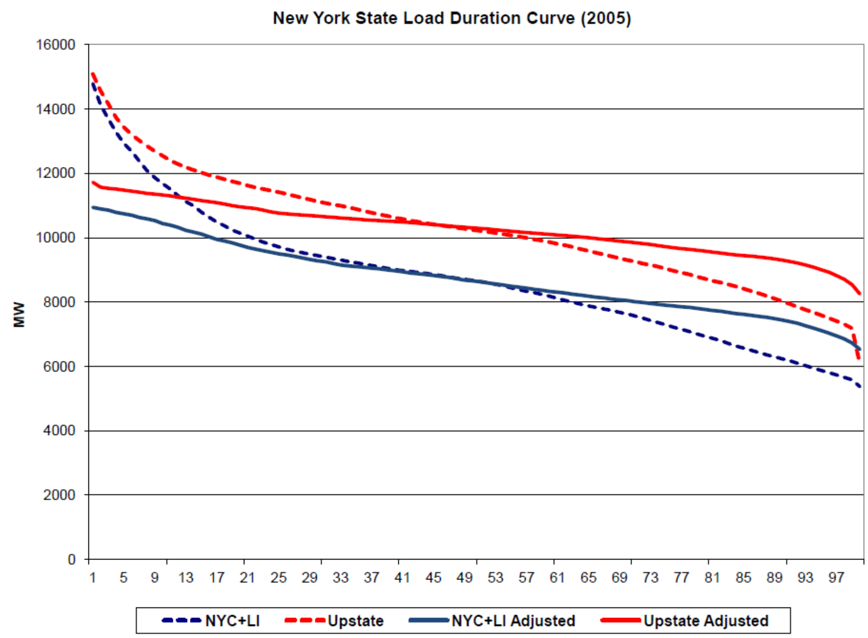

Figure 5.1: New York State Load Duration Curve before adjusting load (dotted lines) and after adjusting load (solid lines), year 2005

Table 5.2 summarizes the key simulation results of replacing the original load duration curves with the modified load duration curves. Other specifications in the simulations are the same as the ones used in Chapter 3. However, only two levels of wind penetration (0 MW of wind and 105 MW of wind), with and without an upgraded tie line, are considered. Using the modified load duration curves, the results show once again that adding wind capacity to the network reduces the operating costs for conventional generating capacity drastically but increases the amount of installed capacity needed for maintaining System Adequacy to cover the contingency when the wind turbines cut out at high wind speeds. Consequently, the additional money paid to the conventional generators to ensure Financial Adequacy also increases because there is more installed capacity and a higher price of capacity. In other words, the savings in the direct wholesale payments are offset by larger indirect payments in the capacity market, and the Total Annual System Costs between the cases with no wind and with 105 MW wind are about the same ($122,590/year for no wind and $123,579/year for 105 MW wind). Nevertheless, both of these totals are substantially less than the equivalent totals using the unmodified load duration curve ($139,054/year for no wind and $139,272/year for 105 MW wind). The main reasons for these lower total costs with the modified load duration curves are the large reductions in the amount of installed generating capacity (from 283MW to 216MW with no wind, and from 288MW to 235MW with 105MW of wind). In contrast, the corresponding savings in the Operating Costs are modest.

A second conclusion implies that the savings in the Total Annual System Costs from a tie line upgrade are substantially less with the modified load duration curves than they are with the original load duration curves in both cases with no wind and with 105MW of wind. The reason is that modifying the load duration curves reduces the peak system load and the amount of congestion on the network. This in turn reduces the system benefits from upgrading transmission.

Another important comparison is to compare the change in the Total Annual System Costs from upgrading the tie line with the original load duration curves to modifying the load duration curves. In both cases, the initial system is the same with a Total Annual System Cost of $139,054 with no wind and $139,272 with 105MW of wind. After upgrading the tie line, the corresponding costs are reduced to $131,878 and $132,342. However, the reductions to $122,590 and $123,579 from modifying the load duration curves are much larger. For these scenarios, controllable demand is an effective substitute for upgrading the tie line.

Table 5.2: Table comparing between the original load duration curve and the modified load duration curve

	Original Case					With Modified Load Duration Curve Case			
	no wind	**105MW**	**no + UP**	**105+UP**		**no wind**	**105MW**	**no+UP**	**105+UP**
Load Not Served (Hours/Year)	16	4	15	4		16	2	16	1
Gen Capacity Needed (MW)*	283	288	288	286		216	235	216	242
Annual Wind Capacity Factor (%/Year)	0%	16.64%	0%	18.39%		0%	18.61%	0%	19.09%
Load Paid ($1000/Year)	$68,915	$22,373	$66,171	$14,705		$60,121	$12,657	$60,543	$8,874
Customers view									
Fuel Costs	$14,005	$11,474	$13,722	$10,504		$12,755	$9,844	$12,776	$9,784
Net Ear Gens	$54,324	$9,872	$55,638	$7,909		$48,980	$6,442	$49,358	$4,003
Net Ear Wind	$0	$186	$0	$722		$0	$207	$0	$181
MM Paid to Gens	$40,639	$87,715	$32,422	$83,178		$30,782	$77,069	$30,223	$79,261
ISO Redistributed	$586	$840	-$3,189	-$4,430		-$1,614	-$3,836	-$1,591	-$5,093
MM Trans	$29,414	$29,160	$33,189	$34,430		$31,614	$33,836	$31,591	$35,093
VOLNS	$86	$24	$96	$29		$74	$17	$74	$4
Total	$139,054	$139,272	$131,878	$132,342		$122,590	$123,579	$122,432	$123,232

A final conclusion addresses the observation that adding wind generation increases the Total Annual System Costs for both the original and modified load duration curves. An important reason for the increases is the need for more installed capacity to cover the contingency. Nevertheless, these results ignore the potential for using controllable demand to mitigate wind variability as well as shift load to off-peak periods. Using this capability, additional savings would come from reducing the installed capacity needed for System Adequacy by modifying the adverse effects of the contingency when wind turbines cut out at high wind speeds. Evaluating the effects of this type of capability would be a good topic for future research.

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