Market Mechanisms and Price Volatility in New York Electricity Markets

By

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Abstract

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The past two decades have born witness to a cascade of new legislation and market design measures to restructure the United States' electric power industry from price-setting regulatory agencies to competitive markets. Deregulation was intended to increase competition and improve market efficiency while preserving the reliability of the transmission system. Results have varied in success, and deregulation has invariably led to an increase in both the overall price level of electricity and volatility of those prices. Investigating these deregulation consequences is crucial for market operations and retrospective analyses of deployed mechanism outcomes.

The objective of this study is to extend the methodological research of Hadsell (2007) in examination of the effect of three market deployments and one exogenous factor on price volatility in the Capital Zone of the New York Independent System Operator (NYISO) markets. To accomplish this end, a Generalized Autoregressive Conditional Heteroskedasticity (GARCH) model is used to model the conditional variance, or volatility, of a constructed return series of Real-Time prices.

The GARCH models found an association between the three market deployments and a reduction in price volatility. These variables included: Lake Erie Loop Flow mitigation measures; establishment of a centralized wind forecasting system; and economic dispatch of wind resources. Furthermore, this study confirmed the association of Thunderstorm Alert (TSA) announcements and an increase in price volatility.

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CHAPTER 1

Introduction

The past two decades have witnessed a cascade of new legislation and market design measures to restructure the U.S. electric power industry. Until the onset of deregulation, regulatory agencies governed the locally monopolistic, investor-owned utilities (IOUs) and power pools that distributed power across individual states and regions. Reform of this vertically tiered generation, transmission, and distribution system has transformed this industry from one in which regulatory agencies set prices to one where markets determine the price level. Deregulation was intended to increase competition and improve market efficiency while preserving the reliability of the transmission systems.

Unfortunately, the outcomes of these deregulation efforts have varied in their success. Failure was exemplified in California's attempted transformation in the late 1990s and early 2000s. Due to partial-deregulation of this state's markets, further exacerbated by drought-diminished hydropower production and limitations on the natural gas supply, the structure plunged multiple IOUs as well as the entire State of California into financial distress (Sweeney, 2006). By contrast, New York successfully moved from its state-regulated New York Power Pool (NYPP) to the New York Independent System Operator (NYISO), an "independent entity" authorized by the Federal Energy Regulatory Commission to operate New York's wholesale electricity markets (NYISO, 2011). These two cases are ideal for a comparative study of the deregulation process and potential outcomes.

A shared negative characteristic of all deregulated markets is an associated increase in price volatility following the implementation of the reforms. Due to the nature of electricity production, higher price volatility is an inherent outcome in this competitive market when compared to traditional commodity markets (Hadsell et al., 2004; Benini et al., 2002). Furthermore, Johnston (2001) confirmed broad consensus that deregulation has been accompanied by an increase in price level. The transition from regulatory agencies to wholesale competitive markets has undoubtedly brought increases in both the overall price level of electricity as well as the volatility of these prices.

Hadsell et al. (2004, 24) and Benini et al.l (2002, 1354) state the benefits of understanding these characteristics of the electricity market are numerous, and include, but are certainly not limited to, future spot price forecasting, proper risk management, and understanding the overall impact of deregulation.

Electricity market operators conduct continuous refinements in an attempt to reduce price volatility through various market design implementations. Hadsell (2007), for example, finds a link between the implementation of a market mechanism called virtual bidding and a reduction in price volatility in the NYISO markets. Published literature has confirmed the value of analyzing price volatility, by itself and in relation to measures taken to address its presence as well. These studies have been conducted on markets around the world, ranging from England and Wales (Tashpulatov, 2011) to Australia (Thomas and Mitchell, 2007). Many more have considered markets within the United States, a number of which are discussed herein. However, very few have explored price volatility in New York markets.

Hadsell (2007) is the primary source for this analysis on price volatility in New York electricity markets. Where he showed an associated link between virtual bidding and a reduction in market price volatility, this study will extend his methodological research to examine the individual effect of three additional NYISO market design mechanisms and one exogenous factor on price volatility in the Capital Zone of the New York markets. Specifically, this paper employs a Generalized Autoregressive Conditional Heteroskedasticity (GARCH) model to investigate the following: implementation of the Lake Erie Loop Flow mitigation measures; establishment of a centralized wind forecasting system; inclusion of wind resources in NYISO's economic dispatch; and announcement of Thunderstorm Alert (TSA) events.

Given the objectives and nature of the three implemented policies, it is expected that they will be associated with a reduction in price volatility after their effective date. In contrast, there is a predicted increase in price volatility associated with TSAs due to increased costs related to the sequence of events that follows such an alert.

The following chapter provides an overview of the electricity market deregulation transition, assorted outcomes, and further refinements introduced specifically within New York markets. The third chapter presents the collected data and describes the analytical approach and econometric tools used in this study. Presentation and analysis of the empirical results follows in the fourth chapter. The study concludes in a final chapter discussing policy implications, shortcomings of the current research, and suggestions for further research.

CHAPTER 2

Overview and Review of Existing Literature

This chapter explores the progression of electricity markets through the deregulation process. In a chronological format, it begins by providing an account of the transition from the regulated era to the current state of deregulated markets. This is succeeded by a review of literature on the process outcomes, paying particular attention to the consequential increase in price level and volatility within the markets and an exploration of the dissimilar cases of California and New York. Conclusively, this chapter addresses a number of market refinements NYISO has made after its establishment as the wholesale electricity market operator.

2.1 Regulation Era

Prior to the onset of deregulation in the U.S. electric power industry, regulatory agencies governed various locally monopolistic investor-owned utilities (IOUs) and power pools that distributed power across individual states and regions. While generation, transmission, and distribution generally took the form of vertically-structured, regulated monopolies (NYISO, 2011, 1), various arrangements included, but were not limited to, the configuration of Power Pools, reliance on voluntary multiple utility cooperative management, or domination by a select few electric companies. Focusing on two case studies set herein, California and New York present two different forms of regulated transmission systems prior to the deregulation period and are an excellent model of contrastive solutions to the distribution of power.

2.1.1 Local Monopolies: California

During the regulated era, power across the State of California was provided by three major investor-owned utilities (IOUs): Pacific Gas & Electric Company (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E). As is evident of Figure 2.1, there existed additional smaller utilities and specific municipal power suppliers like the Los Angeles Power and Electric Company; however, the three primary IOUs supplied 78% of the state with power (Sweeney, 2006, 320). The utilities' vertical integration often meant that generation, transmission, and local distribution were controlled by these area-specific monopolies. While their financial decisions were subject to regulation by the California Public Utilities Commission (CPUC), conducted analyses determined that, rather than reflecting market conditions, market prices were based primarily on cost of service (Sweeny, 2006, 320).

Figure 2.1: California Distribution Zones by Utility: Regulation Era
1996
(Source: Sweeney, 2006)

2.1.2 Power Pool: New York

While a limited number of electric utilities also supplied New York power prior to deregulation, their fate took a twist unlike that of California. Operating in a voluntary cooperative effort, the following eight companies primarily controlled the New York electric distribution network: Consolidated Edison, Long Island Lighting Company, New York State Electric & Gas Company, Niagara Mohawk Power Corporation, Orange & Rockland Company, Rochester Gas & Electric Company, Central Hudson Gas & Electric Company, and the New York Power Authority (Tierney and Kahn, 2007, 5). However, after twenty-five million people were left without power for a maximum of twelve hours during the Great Northeast Blackout on November 9, 1965, these companies deemed it necessary to form a statewide wholesale institution (NYISO, "NYISO Timeline," 2012; Tierney and Kahn, 2007). The New York Power Pool (NYPP) was funded by state-regulated consumer rates to operate grid management and reliability functions including, but not limited to, economic dispatch of generators and balancing real time supply and demand (NYISO, 2011; Tierney and Kahn, 2007). However, utilities were able to commit their units as they saw fit, rather than allowing NYPP to choose from all state units as in a centralized unit commitment system characteristic of other power pools of the northeast. This limited the pool of available plants and reduced the efficiency of the choices made by NYPP in economic dispatch (Tierney and Kahn, 2007, 5-6).

2.2 Deregulation Process

2.2.1 Why Deregulate?

Although electricity systems of the regulated era were not unsuccessful in providing electric power to consumers, many experts of the time contended that these were not as economically efficient as was possible, dominated as they were by regulated monopolies (Sweeney, 2002, 2). Deregulation was thus an attempt to stimulate competition among market participants; this was presumed to carry the additional result of lowering the high system costs and corresponding retail rates (NYISO, 2011, 1;

Sweeney, 2006, 326). A component of the high prices included concern that utilities were not dispatching the next least-cost resource, but providing generation from plants as desired without concern for minimizing costs (Sweeney, 2006, 326). Proponents of deregulation stressed such projected economic benefits, which provided ample support for progression into the deregulation process.

2.2.2 Influence of England and Wales

Power pools of the Northeast provided evidence that electricity distribution could be managed efficiently through one organization. The establishment of the England and Wales wholesale electricity market added further fuel to the movement for change in electric power distribution management (O'Neill et al., 2006). This sprawling transmission system was established in April 1990 and transcended boundaries between the two countries, providing electricity to a wide expanse of territory (Green, 1998). According to Green (1998):

> The ideological beliefs underlying the restructuring were that private ownership and the profit motive gave far better incentives than the most benevolent kind of state control…and that competitive private industries gave better results than monopolies. (2)

The market's use of auction pricing managed by a central grid company demonstrated the ability of a chief management body to successfully handle a diverse array of supply and demand requirements (Tashpulatov, 2011). The rules and accomplishments of the England and Wales market in combination with the success of power pools within the Northeast of the United States provided strong evidence in support of centrally organized markets in the United States (O'Neill et al., 2006).

2.2.3 Deregulation Legislation

Establishment of auction-based markets managed by a centralized body was furthered through a series of acts and orders initiating the transformation of the varying operational systems established in California and New York. Restructuring movements began with the establishment of the Public Utilities Regulatory Policy Act of 1978 (PURPA). This required the purchase of power from smaller generating facilities, or "qualifying facilities" (QFs), by utilities in an attempt to increase investment in renewable and cogeneration power plants and boost competition (O'Neill et al., 2006, 481); the payment rates were based on the "avoided cost" of producing the power from their own generating units (Sweeney, 2006, 324). Although O'Neill et al. (2006, 483) states the 1980s and early 1990s were witness to a decline in PURPA-driven investment due to "declining fossil fuel prices, reductions in renewable energy subsidies, qualifying tests and other factors," Figure 2.2 provides evidence that investment in QFs specifically within California significantly increased after the establishment of this Act, so much so that the total capacity of QFs brought online from 1978 to the beginning of January 2000 exceeded that of the combined output of invested conventional and nuclear generation.

Although PURPA could force utilities to purchase some power from QFs, these companies still controlled transmission lines. To combat this competition issue and motivated by the success of PURPA in generating investment in independent QFs, the Energy Policy Act of 1992 (EPACT) was implemented across the country requiring open-access for transmission lines to non-utilities (O'Neill et al., 2006, 483; Sweeney, 2006, 325). Further force would be given to this act four years later when the Federal Energy Regulatory Commission (FERC) issued Order 888.

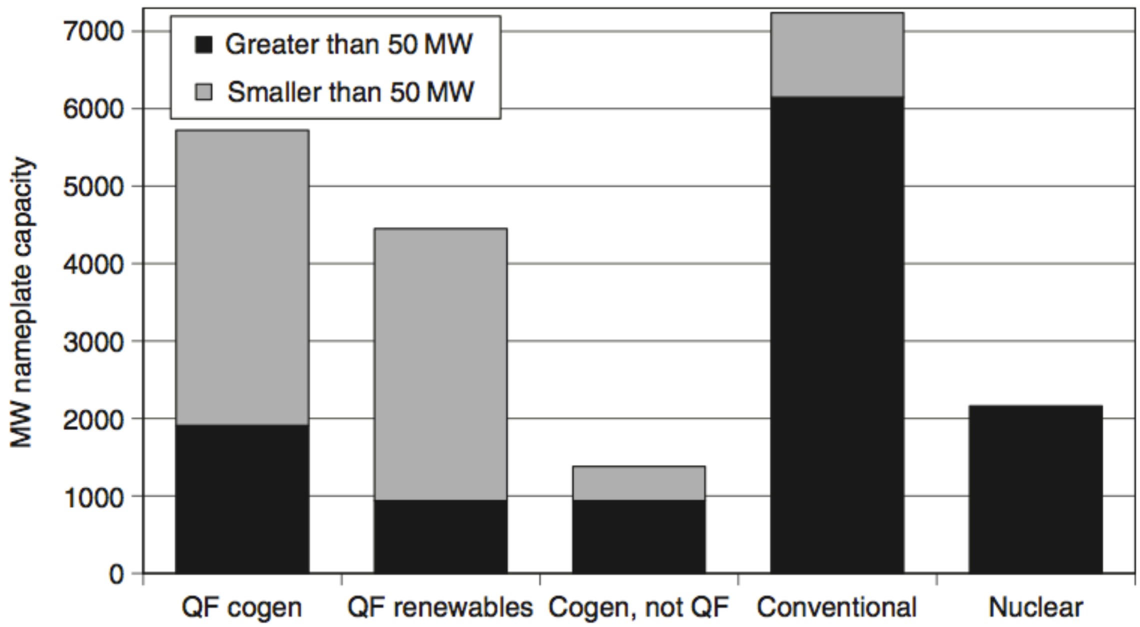

Figure 2.2: "Qualifying Facility" Generation: New Plant Construction
1978 – January 2000
(Source: Sweeney, 2006)

With pressure for more competition among utilities, it was only logical to begin formulating the basic concepts of an established market with a centralized organizational body. California issued its "Blue Book" on March 31, 1994, which drew on the rules of the England and Wales market to lay down a proposal for a competitive wholesale market (Joskow, 2006). The principles of a centralized market manager were expanded upon in FERC Order 889 in 1996, and provided the basis for the creation of Independent System Operators (ISOs) that would organize and administer the wholesale electricity markets. ISOs were to be separate from political and federal agendas, although still subject to the jurisprudence of FERC. Finally, divestiture of utilities and their generators was both strongly encouraged by the New York State Public Service Commission's Competitive Opportunities Proceedings in 1997 (NYISO, 2011; NYISO, "NYISO Timeline," 2012) and highly incentivized by the CPUC in California in 1998. The latter required the divestiture of 50% of generation, and provided generous financial incentives for the latter; by April of 1999, all utilities had separated from their generators (Sweeney, 2006, 329; 338).

2.2.4 Restructuring Architecture

Joskow (2006) and Littlechild (2006) provide an interesting theoretical approach behind deregulation, outlined as "textbook architecture" for restructuring; when followed appropriately, the steps promote competition and ensure the success of electricity markets. Process privatization is one of the most important aspects enabling fair competition without influence by political or participating parties. Removal of vertical monopolies and creation of a horizontally competitive industry of utilities and generators go far to both ensure that one market participant cannot dominate or manipulate market prices as well as to enable easier supervision of all market players. Implementation of regulations such as Order 888 ensuring transmission line access to non-utilities promotes new generation participation and works to add competition on the power supply side. These steps were completed prior to the issuances of Order 889 and later legislation, which advance the subsequent components of restructuring. Contractual and real-time energy and ancillary markets ensure economically efficient distribution of power and should be administered by a central impartial ISO. To ensure competition in the retail realm, inhibiting factors such as retail tariffs must be removed; to ease transition into a competitive retail market, it will be necessary to help power suppliers until such competition is ensured, exemplified by California's attempts at stranded cost recovery. Finally, for such a transition to succeed, independent regulatory agencies must be able to ensure competition is promoted and additional efforts must be given to anticipate potential issues arising during this process of deregulation (Joskow, 2006, xvii; Littlechild, 2006, 4-6).

2.3 Deregulation Outcomes

2.3.1 Unintended Consequences: Price Level and Volatility

Electricity markets produce characteristically higher levels of price volatility, attributable to many reasons, which include the physical nature of electricity as non-storable, inelastic demand for its supply, and unpredictable prices of inputs (Hadsell et al., 2004, 23; Benini et al., 2002, 1354). These can cause significant difficulties in maintaining overall stability of the grid due to the challenge of constantly matching generation supply with demand for power (Borenstein, 2001, 2). In terms of volatility, Hadsell et al. (2004, 23) reports that deregulated competitive wholesale markets "exhibit levels of price volatility unparalleled in traditional commodity markets." Deregulation did not appear to alleviate this volatility nor decrease the overall price level; indeed, common to all deregulated markets, were characteristic increases in both. Johnston (2007, 1) testifies that those states that have undergone deregulation portray a characteristically greater increase in prices than those who remained with government-set price levels. This is indeed supported by findings of the U.S. Energy Department, who reported a near-tripling price level difference charged to industrial companies participating in regulated versus deregulated markets between 1999 and July 2006 (Johnston, 2007, 1).

Increases in price level and volatility were not characteristics confined to deregulated markets in the United States. Tashpulatov (2011) examined the volatility of prices in the England and Wales electricity market from 1990 through 2001. As discussed above, the rules of this market were highly influential in the reconstruction and resulting structure of the United States markets. While Tashpulatov (2011) determined the implementation of a price-cap was successful in reducing prices, it also increased volatility. The subsequent utility divestiture of generation and distribution was associated with a reversal of this trend; while volatility decreased, the overall price level increased. A reduction in both measures was only apparent following a second and final round of divestitures.

2.3.2 Importance of Market Analyses

Varying results for market alterations employed in the England and Wales deregulation process provides reason for continuous reassessment of current market conditions to ensure the original intention of a market change was in fact achieved. If England and Wales had ceased its deregulation process at the initial price cap with its consequential increase in price volatility or after the first round of divestitures with its associated increase in overall price level, there may have been detrimental long-term effects on the market. Evidence of increased price level and volatility in this market combined with its strong influence on the deregulated market structures within the United States lends significant support to the importance of reassessment measures in the United States' markets as well.

The findings of Tashpulatov (2011) support the arguments of Hadsell et al. (2004) in his assertion that there are great benefits to studying and understanding price levels and volatility in electricity markets. The transition from government-set prices to wholesale competitive market has brought undeniable increases in both the overall price level of electricity as well as the volatility of these prices. Hadsell et al. (2004, 24) reports that the benefits to understanding these deregulation results includes, but is certainly not limited to, future spot price forecasting, electricity futures and energy derivatives pricing, and understanding the overall impact of deregulation. Accurate predictions of future prices, in particular, are extremely vital to market participants, whose risk of involvement in the markets is highly correlated to volatility levels. Risk reduction consequentially brings greater confidence to the utilities and generators with regards to their involvement and investment in the wholesale market.

2.3.3 Structural Variations: California and New York

The intended outcome of deregulation was to increase market competition and ensure that demand and supply of electricity met at the most economically efficient manner. However, varying results have occurred, and this study continues with the contrasting examples of California and New York. Both received approval from FERC for the formation of an ISO, and in 1998 and 1999, the California and New York ISOs (CAISO and NYISO) were respectively established. However, the markets managed by each state's ISO were quite different. California's system was split between two separate market operators: the Power Exchange (PX) managed the Day-Ahead (DA) spot markets via zonal pricing, while CAISO handled the grid operation, including congestion management, as well as ancillary services and the Real Time (RT) market (O'Neill et al., 2006; Sweeney, 2006). In contrast, NYISO handled both DA and RT markets. These were conducted with Locational Based Marginal Pricing (LBMP), or the price at each network bus corresponding to the marginal cost of an additional increment of energy; in essence, LBMPs reflected the next least-cost resource available based upon transmission system constraints such as congestion (O'Neill et al., 2006; Sweeney, 2006). In addition, NYISO managed operating reserves and zonal Installed Capacity (ICAP). However, these variations in structure were not the only factors resulting in the dramatically different outcomes of deregulation within these two states.

2.3.4 Failed Outcome: California

The structure taken by the CAISO markets as described above lent itself to the catastrophic deregulation failure that occurred in California. Extensive studies have attributed the so-called California Electricity Crisis to this deregulation. However, subsequent analyses suggest that it is not the fact that the California markets were deregulated but rather that the markets were only partially deregulated which ultimately led to extensive problems. Littlechild (2006, xix) states, "the main problem, in short, was one of inappropriate regulation, and was not attributable to privatization or competitive markets per se." Sweeney (2006) contends that the California Electricity Crisis is actually a combination of an electricity and financial crisis, and neither of these were a direct result of deregulation.

> The western electricity crisis was primarily the product of a "perfect storm", a combination of simultaneous adverse conditions, of flawed market rules, and only secondarily of exercise of market power and market gaming. The financial crisis was the direct result of California regulatory actions. However, the financial crisis was not the result of *deregulation*, but rather of inappropriate *regulation*. (Sweeney, 2006, 379-380)

The continued regulation of certain aspects of the California markets was illustrative of acute government mismanagement (Sweeney, 2002, 10). Legislation was originally issued with the intention of helping utilities recover stranded costs of investment in high-cost generation prior to deregulation with the predicted wholesale price decrease; this was to be accomplished through a "competition transition charge" (CTC) issued by utilities to their retail customers (Sweeney, 2006, 327; 330). However, these were first limited in size, then finally converted to retail-level price caps, set at 10% below their June 10, 1996 levels (Sweeney, 2006, 332-333), effectively ensuring price increases at the wholesale level were nontransferable to end-use consumers. Consequently, utilities were forced to absorb price shocks and retail prices did but reflect fluctuations in the wholesale market. Sweeney (2002) argues that if this cap had not been established, price increases in the wholesale market would have been much smaller.

Inappropriate governmental interference continued with the prohibition of the formation of long-term contracts. This effectively prevented utilities from hedging against potential price fluctuations and forced them to purchase primarily in spot markets, where they were subject to uncertain but standard price volatility (Sweeney, 2006, 319; 333). The *Manifesto on the California Electricity Crisis* (2003) asserts that even with price caps preventing the transfer of price spikes to retail consumers, if utilities had not been purchasing 50% of their power on the sport markets, the financial crisis of the utility companies would have been mitigated. Unfortunately this was not so, and when input prices rose for generators, utilities were forced to buy at a higher price than that at which they were capable of selling; indebtedness followed by bankruptcy were only to be expected. This was the fate of two of the three largest utilities (Figure 2.1); PG&E filed for bankruptcy in April 2001 and SCE flirted with a filing for reorganization until they reached a rate agreement with the CPUC (Sweeney, 2006, 366).

Consequences of "gross mismanagement by the California governor and the CPUC" were further exacerbated by adverse and unforeseen factors (Sweeney, 2006, 10).

These included summer heat waves in 2000 and an unusually cold winter of 2000-2001, where increased demand resulted in significant price spikes, as well as a corresponding widespread three-year drought that restricted critical hydroelectric generation (*Manifesto on the California Electricity Crisis*, 2003; Said, 2001). Inadequate generation capacity inevitably led to increased prices on or near peak load. Aggravation of the issue continued with limited natural gas pipeline infrastructure and skyrocketing gas prices, the input of which was required to power generators replacing the stunted hydropower (Sweeney, 2006, 345).

Beyond these input issues, flawed structural market design enabled a number of market participants to game the system as well. The most notorious of these market manipulators was Enron Corporation, whose operations caused drastic increases in spot-market electricity prices. Kranhold et al. (2002) reported on the release of memos describing Enron's actions in the market, which revolved around two main market manipulations: (1) the creation of artificial congestion, of which CAISO would pay them to relieve; and (2) the "laundering" of electricity, directly in response to the price caps, whereby Enron would route electricity out of the state and then resell it back into the state at a price unrestricted by the in-state price cap. The memos also named a number of other companies who embarked in price-gouging through artificial energy shortages, which included Reliant Energy, Inc., Dynegy, Inc., Mirant Corporation, and Williams Corporation (Kranhold et al., 2002, 2).

These factors created what Sweeney (2006, 379) dubbed "the perfect storm," all of which fed into the drastic price spikes that were so characteristic of the California Electricity Market Crisis and eventually forced Governor Gray Davis to declare the

California State of Emergency on January 17, 2001 (Said, 2001, 5). Benini et al. (2002) models both the price levels and volatility of this market from 1999 through the end of 2000 (Figure 2.3 and 2.4). Not only does this modeling cover directly before the crisis, but also illustrates the electricity market's meltdown as it occurs. This provides ample ability to compare where "normal" prices were originally leveled to the drastically elevated prices of the crisis as well as the impressive increase in price volatility from 1999 to 2000. In addition, Benini et al. (2002) draws attention to the relative lack of volatility in prices during 1999 and the first half of 2000, prior to the meltdown. Even with the occurrence of doubling gas prices in early 2000, this market exhibits an impressive stability. It must therefore be inferred that the price volatility during the second half of 2000 was caused by the lack of generating capacity during the high demand and artificial energy shortages created by manipulating market participants.

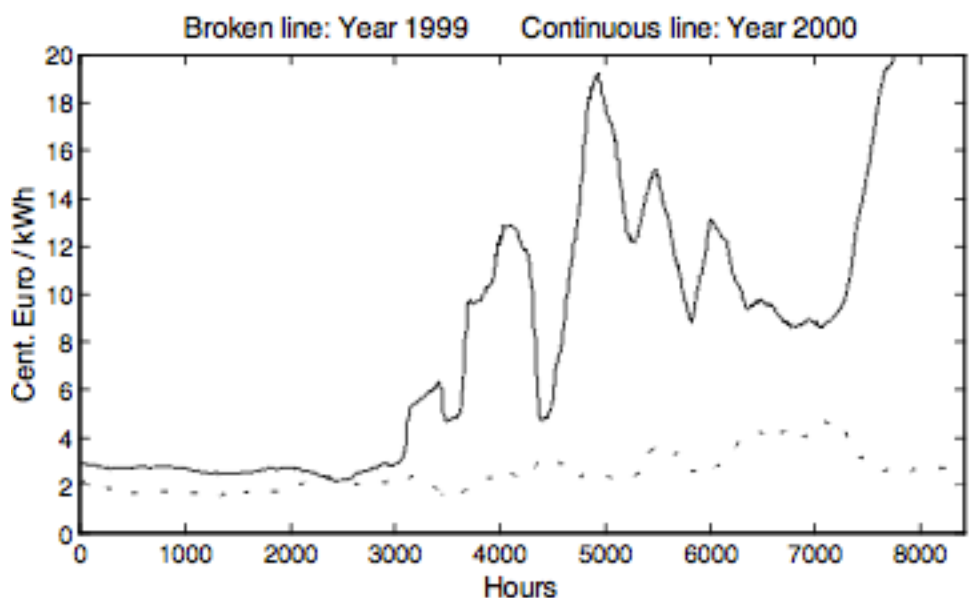

Figure 2.3: Two-Weeks Average Prices in California Markets
1999 – 2000
(Source: Benini et al., 2002)

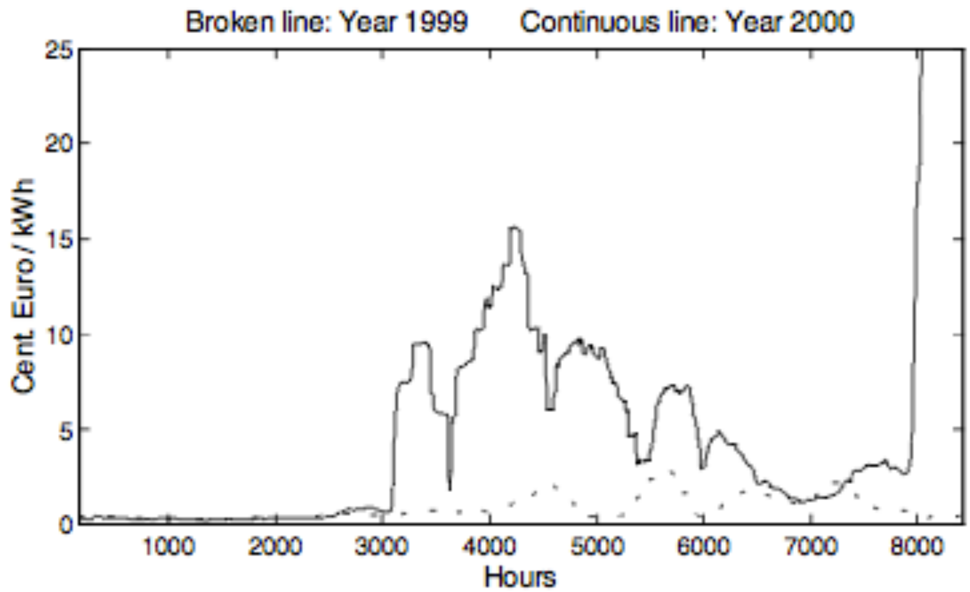

Figure 2.4: Two-Weeks Price Volatility in California Markets
1999 – 2000
(Source: Benini et al., 2002)

2.3.5 Successful Outcome: New York

In contrast to the extensive degree to which California has been analyzed (the authors discussed above are just a minute portion of the bulk of material available), much less attention has been given to New York. Perhaps the "blame" can lie to some degree with the success in which New York has transitioned through the deregulation period. NYISO's Independent Market Advisor stated, "the transition to competitive electric markets have been remarkably smooth given the unprecedented scope of this effort" (NYISO, 2011, 10). Littlechild (2006, 12) states that New York was, in fact, faced with a number of exogenous shock factors, including demand and fuel prices, which contributed to the utter ruin of the California markets, yet New York avoided the fate of California. Evidence provided by O'Neill et al. (2006, 518) suggests that it is due to the prior structure of the system as controlled by a power pool that allowed a smooth transition into a deregulated state to occur. The procedures and reliability functions already existed; it was primarily a matter of transferring power and altering some market rules.

NYISO holds four core values regarding the management of the state's transmission system: "(1) meeting New York's power needs reliably and safely by managing its bulk electricity system; (2) running fair, open and competitive wholesale electricity markets; (3) planning for New York's future power needs; and (4) leading the way in technology of tomorrow's smart grid" (NYISO, 2011, ii). The success of NYISO in achieving these goals is attributed to the "shared governance" of the organization, which includes both an Independent Board of Directors and stakeholder committees. The latter group allows all involved parties, from transmission owners to end-use consumers to environmental groups, within NYISO's system have an opportunity to voice their opinion on the rules and direction of the corporation (NYISO, 2011, 1). In concrete terms of success, NYISO (2011) provided the following information in their Initial Decade Review, which reported NYISO's accomplishments during the development of competitive markets:

- Market participant numbers tripled, from *120* in *2000* to *360* by *2008*;
- Dollar values of annual transactions doubled, from *$5.2 billion* in *2000* to *$11 billion* in *2008*;
- Investment increased in new facilities and upgrades of current facilities;
- Plant efficiency improved, such that the system-wide heat rate of fossil-fueled generation improved by *21%*;
- Average plant availability increased to *94.7%*, which corresponds to an additional 2,000MW, or the amount generated by the investment in 4 new medium-sized plants;
- Wholesale electricity prices (adjusted for fuel costs) declined *18%*;

- Environmental performance drastically improved, such that power plant emission rates[1] dropped by double digits between 1999 and 2008 (NYISO, 2011)

This organization has made undeniable strides in their progress after the deregulation of the markets. In fact, their Independent Market Advisor reported, "NYISO markets are at the forefront of market design, and have been a model for market development in other areas" (NYISO, 2011, ii).

2.4 NYISO Market Refinements

Even with the projected success of the NYISO, the organization continues to make modifications to its rules and market structure in promotion of the most economically efficient and successful manner of running the state's transmission system. The New York Public Service Commission reports that performance metrics incorporating NYISO's continuous advancements "indicate that New York's wholesale markets are among the most advanced in the nation" (Tierney and Kahn, 2007, 7). While this paper cannot hope to encompass the copious range of actions the NYISO has made to enhance its system, this section will give a brief overview of an assorted group of these measures.

2.4.1 New Generation

New generation is intrinsically linked to a decrease in price levels and volatility, particularly if developed in areas with limited generation capacity or afflicted by constraints on the transmission system. From 2000 to 2006, Tierney and Kahn (2007, 7) reported that 5,000 MW of new generation capacity (or about 15% of total capacity in

[1] Power plant emission rates are measured in tons per year of the following components: sulfur dioxide, nitrogen oxides, and carbon dioxide (NYISO, 2011, 4).

2007) was brought online. As is evident of the new generation records in Figure 2.5, these were particularly focused in Long Island and New York City, which are notoriously under-supplied. In 2011, NYISO reported that an additional 2,600 MW had been added to the transmission system in the succeeding three years, 80% of which had been established in the two high-demand areas listed before, as well as the Hudson Valley Zone (Figure 2.6). New generation combined with the enhancements to existing generation as referenced previously, has extensively contributed to alleviating price spikes that occur when nearing or reaching peak load.

Figure 2.5: New Generation Records by NYISO Transmission Area
2000 – 2006
(Source: Tierney and Kahn, 2007)

Unit Name	Nameplate Capacity (MW)	Unit Type	Transmission Area	Installation Date
Jamestown	49	GT	AB	November 2001
Athens	1,080	CC	F	May 2004
Bethlehem Energy Center	750	CC	F	July 2005
Astoria (Poletti) CC	500	CC	J	December 2005
Astoria Energy	500	CC	J	June 2006
East River	360	CG	J	April 2005
Gowanus	90	GT	J	July 2001
Harlem River	93	GT	J	July 2001
Hell Gate	93	GT	J	June 2001
Kent	47	GT	J	August 2001
Pouch	44	GT	J	August 2001
Ravenswood	250	CG	J	March 2004
Vernon Blvd.	95	GT	J	August 2001
Bayswater Peaker	61	GT	K	July 2002
Bethpage	50	GT	K	July 2002
Bethpage Expansion	80	CC	K	July 2005
Brentwood	47	GT	K	July 2001
Freeport 2	48	GT	K	April 2004
Freeport Equus	47	GT	K	June 2004
Glenwood Landing	80	GT	K	May 2002
Greenport	54	GT	K	July 2003
Jamaica Bay	55	GT	K	July 2003
LIPA Temp Holtsville	44	IC	K	July 2004
LIPA Temp Shoreham	44	IC	K	July 2004
Pinelawn Babylon	79	CC	K	October 2005
Port Jefferson	80	GT	K	July 2002
PPL Edgewood Energy	80	GT	K	June 2002
Shoreham	80	GT	K	July 2002

Notes:
Unit types: CC = Combined Cycle, CG = Cogeneration, GT = Gas Combustion Turbine, IC = Internal Combustion.
List excludes 240 MW of wind and 15 MW of small GTs.

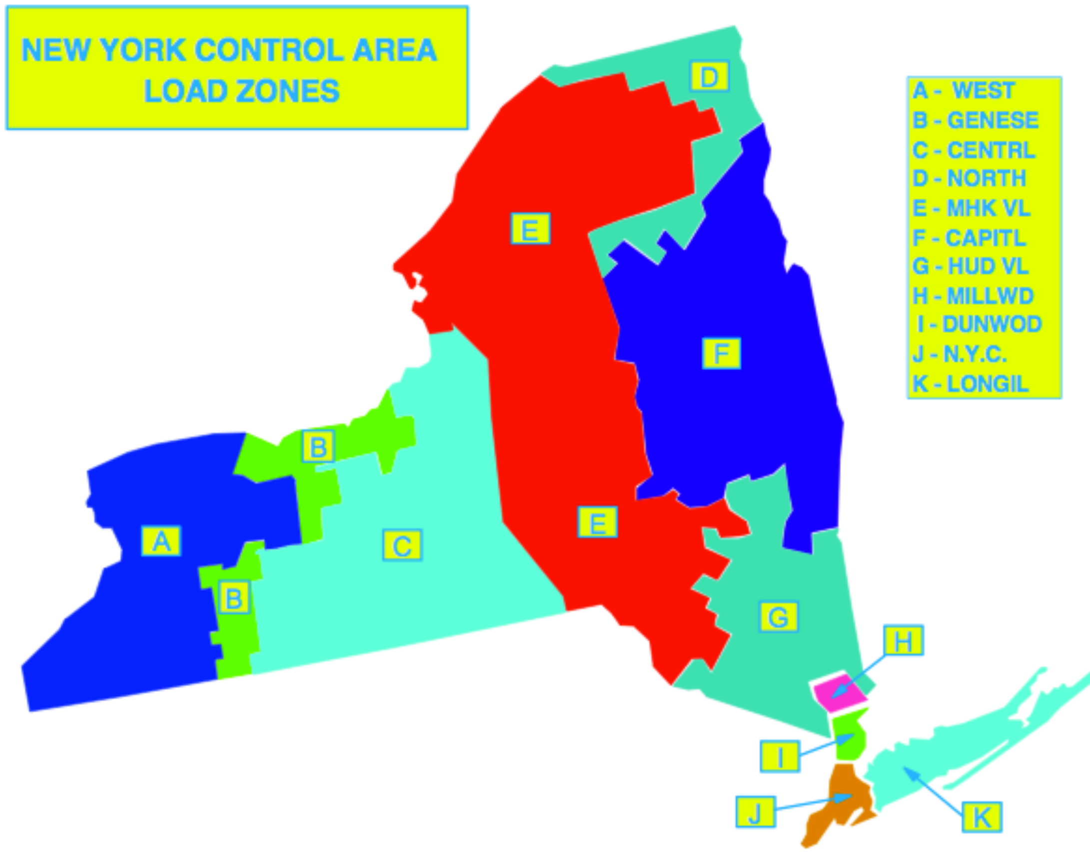

Figure 2.6: New York Zonal Load Map
(Source: NYISO Market & Operational Data)

2.4.2 Demand Response

Demand response (DR) programs are extremely effective instruments used to lessen the effects of high electricity demand during peak-load hours. Albadi and El-Saadany (2007, 3) present numerous benefits to the installation of a demand response program; of particular relevance to this paper is their assertion of the direct correlation to the improvement of market performance through the reduction in price volatility. NYISO has installed a number of market-based DR programs, which include: the Day-Ahead DR Program (DADRP), which allows companies to give bids of reduction, or "negawatts" into the DA market as generators; the Emergency DR Program (EDRP) and

ICAP Special Case Resource (SCR) Program, both of which reduce peak load during energy shortages through shut-down notifications given to participants, who are primarily commercial and industrial consumers; and Demand Side Ancillary Services Program, which allow retail consumers the ability to bid load curtailment into the DA and RT markets (NYISO, “NYISO Demand Response Programs,” 2012). In 2002, it was estimated that 400MW were shaved from peak demand on consecutive record consumption days at the trigger of EDRP (NYISO, “NYISO Timeline,” 2012). This impressive reduction in demand would have aided in depressing price spikes and volatility that inherently occurs as demand nears generation capacity limits.

2.4.3 Standard Market Design (SMD2)

On February 1, 2005, NYISO deployed its current Standard Market Design (SMD2). At a cost of $32 million over two years, this project established RT and DA markets on a common platform (NYISO, 2005). The shared platform was intended to increase the convergence of RT and DA prices, reducing volatility, and provide better historical data to “allow for more informed, precise and economical dispatching decisions (NYISO, 2005, 1). The transition to this new system was facilitated by the co-operation of the old and new processes for one week during this period, which allowed for a smooth and successful changeover (NYISO Insider, 2005). While this deployment was relatively recent, future analyses will be vital in understanding its overall impact. However, this has been arguably the most significant alteration to the New York markets since their deregulation, reflecting NYISO’s understanding and belief that this “era of competitive markets…are more complicated than ever and require the most sophisticated hardware and software available. SMD2 gives us that” (NYISO, 2005, 1).

2.4.4 Virtual Bidding

The implementation of virtual bidding in November 2001 was of particular focus to Hadsell (2007). This market function operates financially settled bids rather than physically contracted agreements, providing both entry into the electricity market field by an increasingly large array of participants as well as a means of hedging against volatility in the markets by physical bidders (Hadsell, 2007, 66). Hadsell (2007) states its designation was to decrease the discrepancy between DA and RT prices as well as general price volatility within the markets; his findings presented statistical proof that the installation of this program was, in fact, associated with a reduction in price volatility.

2.5 Summary

Electricity markets have undergone significant changes throughout the last two decades, beginning first and foremost with the deregulation process. The post-deregulation markets experienced significantly different outcomes, most notably contrastive being the catastrophic meltdown in California and the successful transition of New York. Continued refinements of the New York markets provide ample material for reappraisal and analysis of the results of deployed mechanisms and policies. This was utilized by Hadsell (2007), whose study has provided a means by which to calculate the "success" of certain market implementations conducted by NYISO through the determination of their influence, positive or negative, upon price volatility. Using the methodology of Hadsell (2007) that is discussed in depth in the subsequent section, this study will model three policies as well as an additional extraneous factor for each variable's associated effect on RT price volatility in the NYISO markets.

CHAPTER 3

Econometric Technique and Analytical Approach

This chapter describes the data and its associated variable specifications as well as the model to be used during the analysis. The objective is to determine the impact of specific policies and effects on price volatility. To accomplish this end, a Generalized Autoregressive Conditional Heteroskedasticity (GARCH) model will be used to model the conditional variance, or volatility, of a constructed return series of real-time prices. Inclusion of variables for specific policies or events within the variance equation will facilitate the examination of each variable's effect on the volatility of electricity prices.

3.1 Data

This research focuses on determining the effect of three specific NYISO policies and one exogenous factor on price volatility within New York's electricity markets. The implemented model described below attempts to capture the effect of each variable, which includes both implemented market design measures and potential causes of variability, within the Capital Zone. There is no precise reason for the selection of this representative zone, and each zone will show different levels of volatility based upon location. The Long Island and NYC Zones will undoubtedly show relatively higher price volatility, while those in the western area of the state will show less varying levels (Figure 2.6). One might presume that the Capital Zone is both physically situated, in relation to generation location, and well-populated to show a moderate or "average" level of volatility for the state.

All data used herein are available from the New York Independent System Operator (NYISO) as a collection of time series data covering the time span of January 2, 2006 through December 31, 2012. This range is selected because it provides the seven full years of operational data following the implementation of Standard Market Design (SMD2) on February 1, 2005.[2] During this seven-year time span, 2,534 daily data points are observed. This figure does not include twenty-three dates and associated data due to certain characteristics of the data as described in greater detail below. Descriptive statistics for the data of the following variables are provided in Table 3.1 (Appendix A).

3.1.1 Dependent Variable: Return Series of Price

As discussed in Chapter 2, Locational Based Marginal Prices (LBMPs), as used in NYISO's markets, are unique to each zone of the state. They reflect the marginal cost of adding the next lowest-priced megawatt of energy to the system in \$/MWh (NYISO, "NYISO Glossary," 2012). For the purpose of this study, an average daily value is calculated from the Time-Weighted/Integrated Real Time (RT) Zonal LBMP. RT prices are selected because these spot prices are the basis for driving Market Participant (MP) behavior. The fact that they are "Time-Weighted/Integrated" simply indicates that NYISO has calculated an average price over that hour from the five-minute increments of which it exists. There exist twenty-four hourly intervals for one day, except during Day-Light Savings Time (DST) transitions, during which there are either twenty-three or twenty-five intervals. Similar to the methodology of Hadsell (2007), a return series of these average daily RT prices was constructed as $R_t = \ln(P_t / P_{t-1})$, where P_t is the price at time *t*; this is captured by the variable *P_RS*. Figure 3.1 provides a visual presentation

[2] See the discussion of SMD2 in Chapter 2: Overview and Review of Existing Literature.

of the volatility of this return series. The following dates are removed from the set because the return series calculation is impossible due to the negative value of the daily average, per the aforementioned formula: 1/1/2006; 7/1/2006; 7/2/2006; 7/23/2008; 7/24/2008; 7/26/2009; 7/27/2009; 8/28/2011; and 8/29/2011.

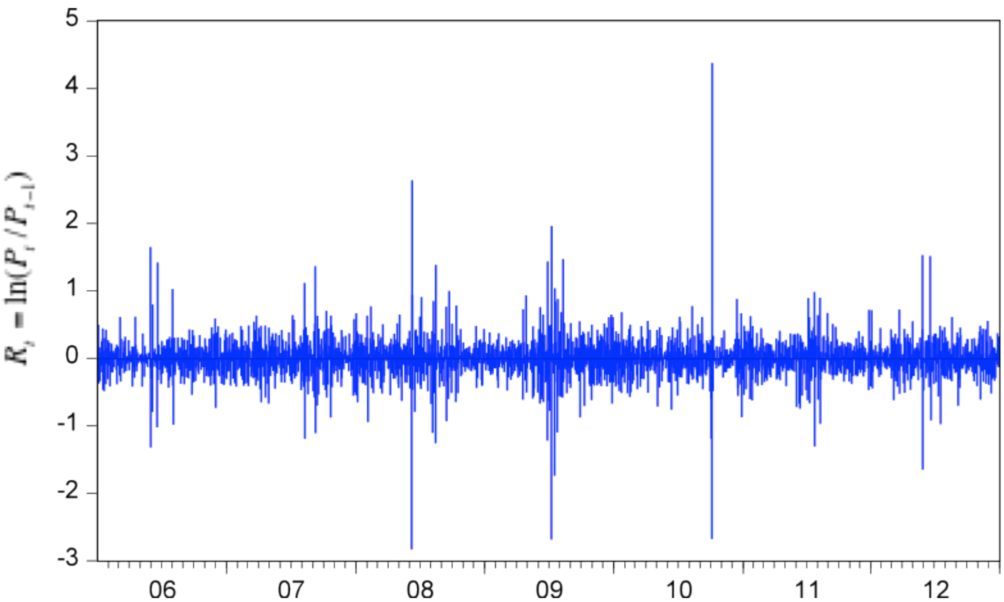

Figure 3.1: Return Series of NYISO Capital Zone Average Daily RT Prices
January 2, 2006 – December 31, 2012
(Source: NYISO Market & Operational Data)

3.1.2 Exogenous Variables

To capture movement within the mean equation, three exogenous variables are included. Integrated Real-Time Actual Load, or volume of demand for electricity, is captured by the *LOAD* variable. While load in the markets is originally constructed in 5-minute increments, similar to the RT prices, NYISO provides this integrated value as the average load over the entire referenced hour measured in MW. A daily average has been calculated from these hourly values, which exist in twenty-four hourly intervals, except during DST transitions, as described above.

NYISO provides a prediction of hourly load, or a forecasted volume of demand, on an hourly basis to help ensure the appropriate level of generation is prepared to meet demand. It is modeled for each zone based upon weather forecasting information and historic load and weather data (NYISO, "NYISO Load Forecasting," 2013). These forecast data have been used to calculate a daily average, measured in MW, and captured by the variable *FRCST*. As referenced above, there are dates that lack associated data; this is not the same as saying the forecast of the day has a value of "0 MW." Thus the data of the following dates were removed due to their lack of forecasting data: 10/16/2007; 3/1/2008; 5/21/2008; 1/26/2011; 1/30/2011; 1/31/2011; 11/6/2011; 11/7/2011; 1/26/2012; and 1/27/2011.

Average marginal costs of congestion within the Capital Zone for this period are captured by the *CONG_AVG* variable. These data refer to the existence of one or more constraints within the transmission system and reflect an inability to economically dispatch electricity at the most efficient level (NYISO, "NYISO Glossary," 2012). This occurs due to physical limitations on the network that prohibits least-cost generation from meeting load requirements; the cost of dispatching the next generator is the marginal cost of congestion (*CARIS 2011,* 2012, 73). A daily average has been constructed from the hourly values provided by NYISO, measured in $/MWh.

3.1.3 Explanatory Variables

To capture the effect of certain events on price volatility, three policy implementations and one exogenous event factor were tested within the variance equation of the model. The first chronological market implementation was mitigation for the Lake Erie Loop Flow incident (*LE08*). The term “loop flow” is defined as the difference between the scheduled bid of energy flow and physical movement of energy (Clamp, 2010). In this case, market participants were scheduling energy bids on a circuitous path around Lake Erie from New York through the markets of NYISO, Ontario’s Independent Electricity System Operator (IESO), Midwest Independent Transmission System Operator (MISO), and PJM Interconnection (Schnell, *Docket No. ER08-1281-000*, 2008). In reality, eighty percent of scheduled electricity, flowing in the path of least resistance, was physically moving directly across the border of NYISO and PJM (FERC, *Docket Nos. ER09-198-000 and ER09-198-001*, 2008).

While scheduling bids in this manner was financially profitable for the market participants due to transmission pricing rules, “these unscheduled flows exacerbate[d] west-to-east constraints in New York, and thereby increase[d] congestion costs,” resulting in market fluctuations and uplift charges, or the cost of relieving the congestion (FERC, *Docket Nos. ER09-198-000 and ER09-198-001*, 2008; Clamp, 2010). To resolve this issue, NYISO received permission from the Federal Energy Regulatory Commission (FERC) for a tariff provision on July 22, 2008, prohibiting this action by market participants (Schnell, *Docket No. ER08-1281-*___ (sic), 2008). Inclusion of this market adjustment as a variable will determine if this was successfully associated with a reduction in price volatility, which would support the importance and benefit of attentive analysis and mitigation of market issues. The data for days prior to the execution date will hold a value of 0 for this variable, while all those after will hold a value of 1.

Renewable energy is an integral and growing aspect of the future of energy. NYISO has established wind as "a rapidly growing segment of New York's power supply and an essential element of the state's portfolio of renewable resources" (NYISO, 2011). Appropriately incorporating these new sources of energy are extremely important as to ensure a reliable supply of energy across the system. The following two variables encompass strides forward made by NYISO with regards to wind resources. On June 18, 2008, NYISO received approval from FERC for the mandatory participation of these resources in providing meteorological data for a centralized wind forecasting system (NYISO, 2010). This would allow the NYISO to more accurately predict the energy output by wind resources within the system (FERC, *Docket No. ER08-850-000*, 2008). To understand the effect of the implementation of a centralized wind forecasting system, the variable *WIND_FRCST* will be modeled such that days prior to the execution date will hold a value of 0, 1 otherwise.

The second variable to encompass NYISO's wind resource incorporation efforts occurred on May 12, 2009 when NYISO received approval from FERC to fully integrate wind resources into its economic dispatch process (NYISO, 2010). Wind is inherently intermittent; in addition, these resources can only be established in areas with specific characteristics favorable for a wind farm (Figure 3.2). This clustering effect combined with intermittent energy production can cause constraints upon the system (FERC, 2009). During these times, NYISO proposed wind units be treated as flexible resources by its grid operators.[3] This wind energy management initiative was intended to "improve the economic efficiency of the real-time market, compared to prior practice" (FERC, 2009). Therefore, the establishment of this market measure will be incorporated as the variable

[3] Please see FERC (2009) for more information on the establishment of wind units as flexible resources.

WIND, whereby all data of days prior to May 12, 2009 will hold a value of 0, 1 otherwise.

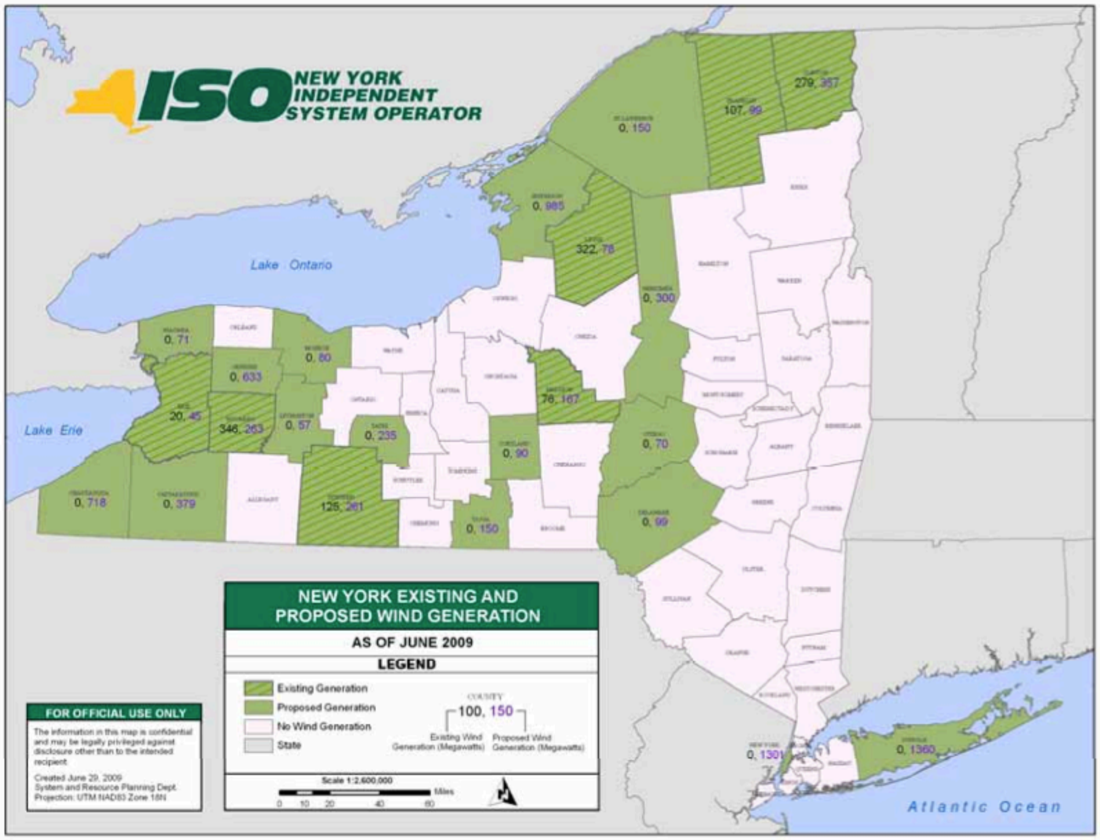

Figure 3.2: NYISO Existing and Proposed Wind Generation
2009
(Source: Yeomans, 2010)

A number of uncontrollable factors have significant impact on price volatility. Accurate forecasting of weather-related events can help prepare for the effects of nature and is therefore an extremely important aspect of electricity market operation. However, adverse conditions such as thunderstorms will still have some effect on reliability of the system and, consequently, electricity prices (NYISO, *MST Section 2 - Definitions*, 2012, 5). Thunderstorm Alerts (TSAs) can be issued quite frequently given the weather patterns of New York State during certain seasons and initiate a region-specific conservative system operation through the reduction of transmission transfer limits (NYISO, "NYISO System Conditions," 2012). Specifically, "NYISO applies the requisite transmission constraint sets to redispatch the transmission grid in a fashion that reliability is effectively supported for the N.Y.C. region" (NYISO, *§8.1.7.1: Storm Watch Costs,* 2013, 8.4-8.5). In essence, generation is turned on within the New York City Zone in anticipation of outages due to lightening strikes; the start-up and minimum generation costs of these generation units as well as the congestion issues resulting from the conservative approach to operation impacts electricity prices (NYISO, *§4.1.8: Commitment for Reliability*, 2013, 11).[4] The effect of a TSA on price volatility will be captured using the variable *TSA*; this variable will hold a value of 1 when such an event is issued, 0 otherwise. To code this variable to these characteristic values, it was first necessary to convert the End Time Stamp of the limiting constraint data, issued in five-minute increments, to an associated Begin Time Stamp. Once all date-linked data was combined, any day with an associated TSA event was coded as 1, those without as 0. Finally, the following dates and coupled data are removed due to their lack of limiting constraint data: 11/12008; 9/5/2010; 3/30/2012; and 5/24/2012.

3.2 Analytical Approach

3.2.1 Model Selection

Much like the work of Hadsell (2007), the methodology of this study will use a Generalized Autoregressive Conditional Heteroskedasticity (GARCH) model. This tool uses past values of the dependent and independent variables (Equation 3.3.1) to model the conditional variance, or volatility, of a variable (Equation 3.3.2), in accordance with

[4] For more information on costs corresponding to TSAs, please reference *NYISO §4.1.8: Commitment for Reliability* (2013) and *NYISO §8.1.7.1: Storm Watch Costs* (2013)

Chapter 24: ARCH and GARCH Estimation (2010). Inclusion of variables for specific policies or events within the variance equation will facilitate the examination of each variable's effect on the volatility of electricity prices.

3.2.2 Model Specifications

The modeling for this analytical approach will employ one regression for each of the four explanatory variables. These will be individually tested within the GARCH model as variables in the variance equation. In all regressions, the return series of RT price (*P_RS*) will run as the dependent variable of the mean specification. All three exogenous variables, *LOAD*, *FRCST*, and *CONG_AVG*, will be included in the mean equation as well. Therefore the GARCH specification will assume the following form:

(3.2.2.1) $$P\_RS = \lambda_1 LOAD + \lambda_2 FRCST + \lambda_3 CONG\_AVG + \varepsilon$$

(3.2.2.2) $$\sigma_1^2 = \omega + \alpha\varepsilon_{t-1}^2 + \beta\sigma_{t-1}^2 + \gamma EV$$

Within the variance equation, the variable *EV* refers to the specific explanatory variable for each test; thus the model will be run once for each of the aforementioned policies and events. Characteristic of a dummy variable, the existence of the explanatory policy or event gives the variable a value of 1, 0 otherwise. The ω variable is a constant term, representative of the mean. The ARCH (ε_{t-1}^2) and GARCH (σ_{t-1}^2) terms refer to news of the previous period's volatility and the previous period's forecasted variance, respectively. Of importance to this paper are the coefficients of the variance specification. The coefficient of the explanatory variable, γ, indicates the effect of this factor on volatility. Per Hadsell (2007), a negative value signifies the variable is associated with a reduction in volatility; a positive value indicates the opposite.

Additionally, the coefficients of the ARCH and GARCH terms, α and β, respectively, are used in the calculation of the point estimate of persistence. The calculation ($\alpha+\beta$) is equal to the "time taken for volatility to move half-way back to its unconditional mean following a given deviation," whereby shocks are transitory in nature if the value holds at less than 1 (Hadsell, 2007, 71). Conversion of this basic calculation through the following formula provides this measurement in days:

(3.2.2.3) $$\text{Half Life} = \ln(1/2)/\ln(\alpha+\beta)$$

Through this methodology, it is expected that the three implemented policy variables, *LE08*, *WIND_FRCST*, and *WIND*, will show an associated reduction in price volatility after their effective date by means of a negative coefficient value. Conversely, *TSA* is predicted to possess a positive coefficient, reflecting the associated increase in price volatility when such an event is issued.

CHAPTER 4

Analysis of Empirical Results

This chapter presents the econometric findings regarding the determinates of price volatility in New York's electricity markets. As described in Chapter 3, the analysis used a GARCH model of the return series of Real Time NYISO Locational Based Marginal Prices (LBMPs) as a function of past values of the dependent and exogenous variables. As expected, the results indicate associated reductions in price volatility related to the implementation of the Lake Erie Loop Flow mitigation measures; the establishment of a centralized wind forecasting system; and the inclusion of wind resources in NYISO's economic dispatch. The model confirmed Thunderstorm Alert (TSA) events were associated with an increase in price volatility. Additionally, TSAs exhibited more than four times the effect on price volatility than the average effect of the other three implementations, as measured by the absolute value of each variable's coefficient.

4.1 Lake Erie Loop Flow Mitigation

The mean equation for this model ran the return series of the average daily price (*P_RS*), constructed in Chapter 3, as a function of past values of the dependent variable and the exogenous variables: average daily load (*LOAD*), or volume of demand; the average daily forecast (*FRCST*), or predicted load; and the average daily congestion (*CONG_AVG*), with an error term, ε. The conditional variance equation contained the ARCH variable, ε_{t-1}^2, GARCH variable, σ_{t-1}^2, and dummy variable for the Lake Erie Loop Flow, *LE08*, whose value changed from 0 to 1 on June 22, 2008, marking the implementation of mitigation measures that prohibited circulation of energy around Lake Erie.

(4.1.1) $$P\_RS = \lambda_1 LOAD + \lambda_2 FRCST + \lambda_3 CONG\_AVG + \varepsilon$$

(4.1.2) $$\sigma_1^2 = \omega + \alpha\varepsilon_{t-1}^2 + \beta\sigma_{t-1}^2 + \gamma LE08$$

As is evident from Table 4.1 (Appendix B), all variable coefficients are statistically significant at better than a 1% level. The negative coefficient on the dummy variable *LE08*, indicates, as predicted, that the implementation of this market measure intended to relieve congestion and the associated price increases correlates to a decline in price volatility. This is visually confirmed in Figure 4.1, where there is a roughly visible decrease in conditional variance around this period. From the coefficients on the ARCH (α) and GARCH (β) terms of the variance formula, it is possible to determine the point estimate of persistence; constructed as described in Chapter 3, it would take approximately 5.15 days for volatility to revert half-way back to its unconditional mean.

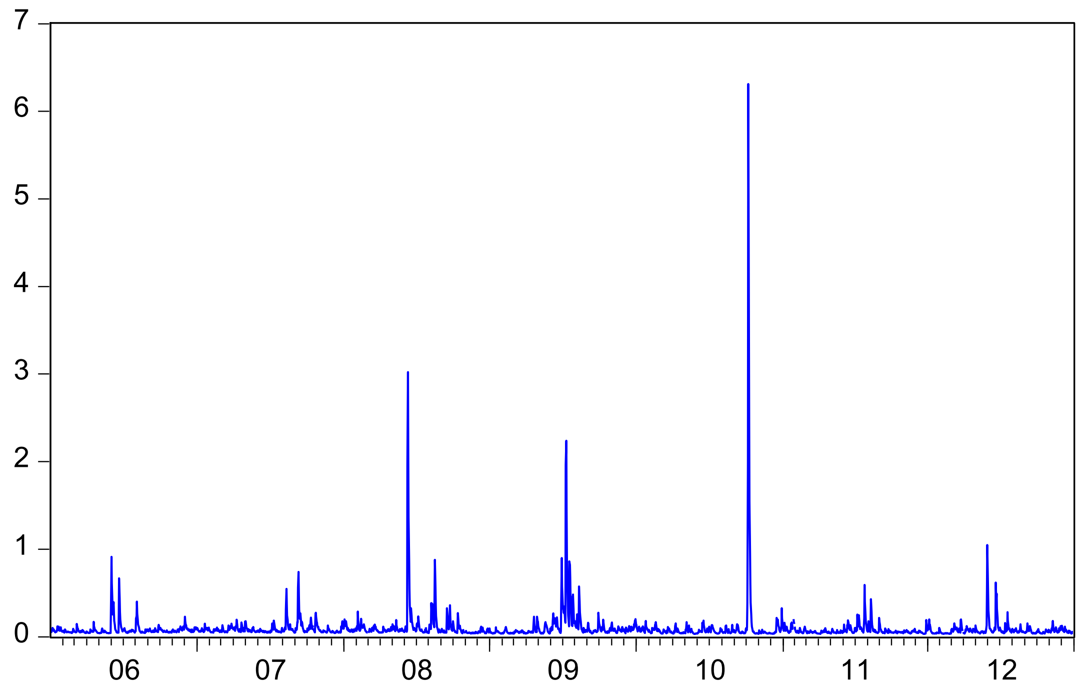

Figure 4.1: Conditional Variance of NYISO Capital Zone RT Price Volatility
Lake Erie Loop Flow Mitigation (*LE08*)
January 2, 2006 – December 31, 2012

4.2 Wind Forecasting

To understand the effect of the implementation of a centralized wind forecasting system, the conditional variance equation of this model was altered accordingly. The mean equation remained a model of the return series of the average daily price (*P_RS*) as a function of the exogenous variables average daily load (*LOAD*), average daily forecast (*FRCST*), and average daily congestion (*CONG_AVG*), with the error term, ε. The conditional variance equation remained constant in its inclusion of the ARCH (ε_{t-1}^2) and GARCH (σ_{t-1}^2) variables, but varied in the included dummy variable; the establishment of wind forecasting was modeled by the variable, *WIND_FRCST*, whose value and thus existence of legislation changed from 0 to 1 on June 18, 2008.

$$P\_RS = \lambda_1 LOAD + \lambda_2 FRCST + \lambda_3 CONG\_AVG + \varepsilon \tag{4.2.1}$$

$$\sigma_1^2 = \omega + \alpha\varepsilon_{t-1}^2 + \beta\sigma_{t-1}^2 + \gamma WIND\_FRCST \tag{4.2.2}$$

All coefficients are statistically significant to the 1% level in this model (Table 4.2, Appendix B). Focusing on the coefficient, γ, of the dummy variable *WIND_FRCST*, its negative value indicates that the introduction of this forecasting system for wind resources in New York's electricity markets is associated with a decline in price volatility. Rough visual confirmation is provided in Figure 4.2, where there is a decline in conditional variance values around this deployment period. Calculated from the ARCH (α) and GARCH (β) coefficients of the variance formula, the point estimate of persistence identifies a measure of approximately 5.16 days following a given deviation for before volatility has moved half-way back to its mean.

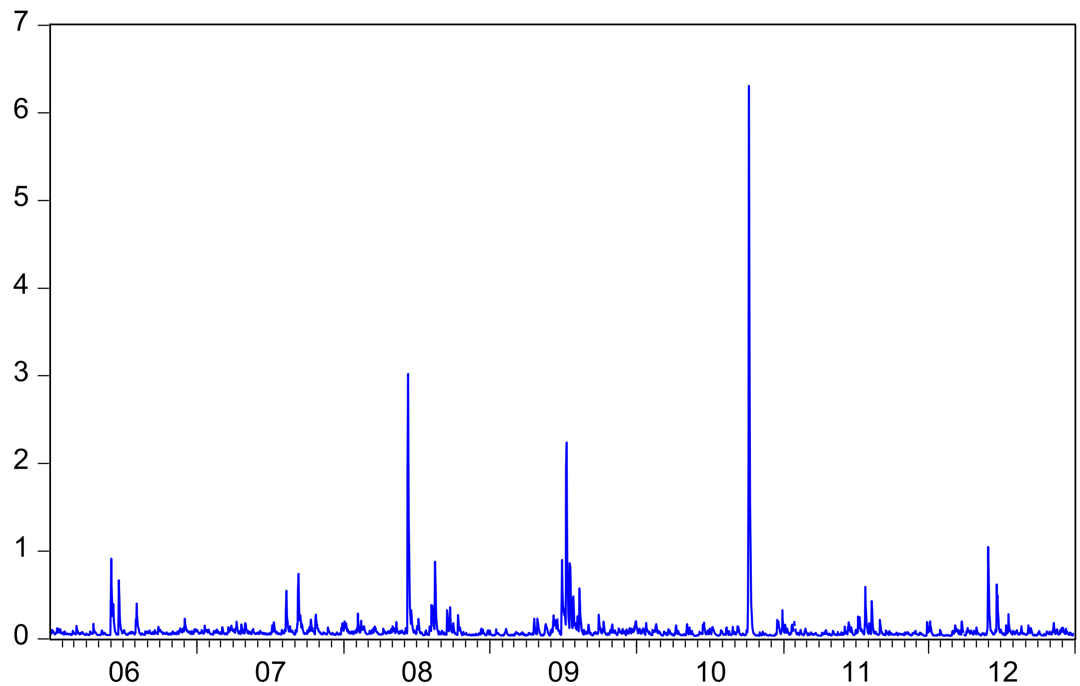

Figure 4.2: Conditional Variance of NYISO Capital Zone RT Price Volatility
Wind Forecasting (*WIND_FRCST*)
January 2, 2006 – December 31, 2012

4.3 Economic Dispatch of Wind Resources

Associated effect of the full incorporation of wind resources into the system's economic dispatch was analyzed with the same modeling process. The return series of the average daily price (*P_RS*) was modeled as a function of the independent variables average daily load (*LOAD*), average daily forecast (*FRCST*), average daily congestion (*CONG_AVG*), and the error term, ε. The dummy variable *WIND* was introduced to the conditional variance equation to represent the implementation of this wind energy management initiative, the value of which changed from 0 to 1 on May 12, 2009. The remaining ARCH (ε_{t-1}^2) and GARCH (σ_{t-1}^2) variables remained constant.

(4.3.1) $$P\_RS = \lambda_1 LOAD + \lambda_2 FRCST + \lambda_3 CONG\_AVG + \varepsilon$$

(4.3.2) $$\sigma_1^2 = \omega + \alpha\varepsilon_{t-1}^2 + \beta\sigma_{t-1}^2 + \gamma WIND$$

This model revealed that all coefficients, excluding that of the dummy variable, *WIND*, hold statistically significant at a 1% level (Table 4.3, Appendix B). The coefficient of the dummy variable *WIND* was negative and significant at a 10% level, holding all else constant. This signifies that the inclusion of wind resources in economic dispatch is correlated to a decrease in price volatility, which is visually confirmed in Figure 4.3. Construction from the ARCH (α) and GARCH (β) coefficients of the number of days for volatility to move half-way back to its mean after a divergence formula estimates a point estimate of persistence of 4.90 days.

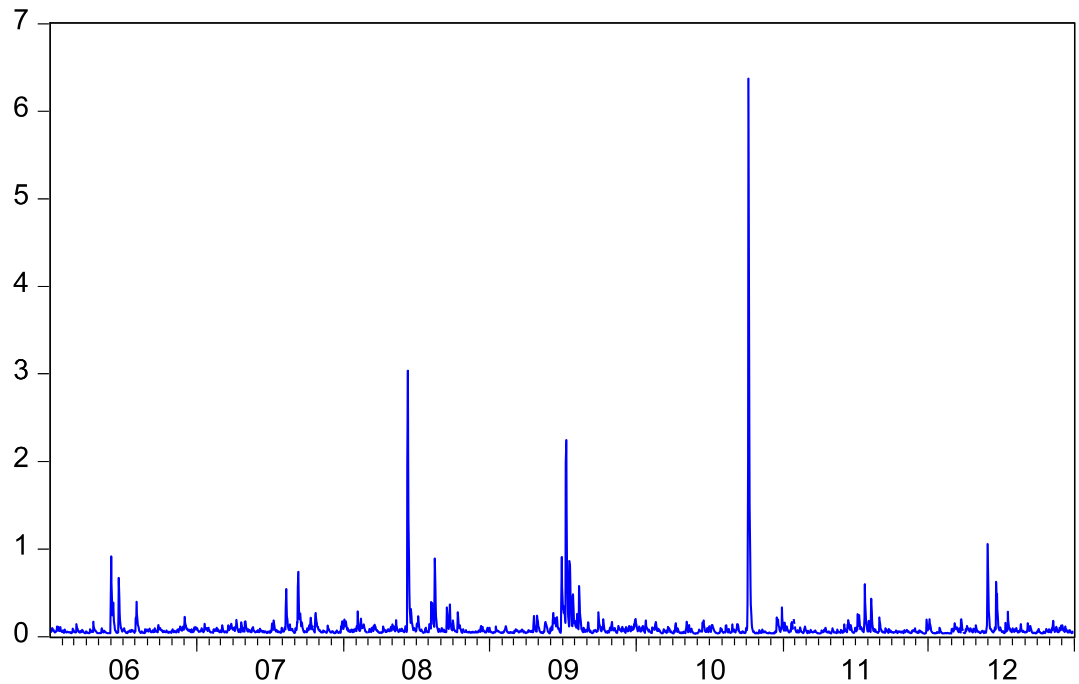

Figure 4.3: Conditional Variance of NYISO Capital Zone RT Price Volatility
Economic Dispatch of Wind Resources (*WIND*)
January 2, 2006 – December 31, 2012

4.4 Thunderstorm Alerts

The model for the effect on price volatility of Thunderstorm Alerts (TSAs) utilized the identical mean equation, whereby the return series of the average daily price (*P_RS*) was a function of the exogenous variables average daily load (*LOAD*), the average daily forecast (*FRCST*), and the average daily congestion (*CONG_AVG*), with an included error term, ε. The conditional variance equation contained the ARCH variable (ε_{t-1}^2), GARCH variable (σ_{t-1}^2), and a dummy variable for days of Thunderstorm Alerts, *TSA*, which held a value of 1 on dates with recorded TSA events and 0 on those without.

(4.4.1) $$P\_RS = \lambda_1 LOAD + \lambda_2 FRCST + \lambda_3 CONG\_AVG + \varepsilon$$

(4.4.2) $$\sigma_1^2 = \omega + \alpha\varepsilon_{t-1}^2 + \beta\sigma_{t-1}^2 + \gamma TSA$$

As is evident from Table 4.4 (Appendix B), all coefficients are statistically significant at a 1% level. The dummy variable *TSA*, of which this paper is concerned, has an associated positive coefficient. This indicates, as expected, the issuance of a TSA event is correlated to an increase in price volatility. This is visually confirmed in Figure 4.4, where the frequency of TSA events is illustrated by the much more volatile conditional variance when compared to Figures 4.1 through 4.3. The point estimate of persistence, as constructed From the ARCH (α) and GARCH (β) coefficients of the variance formula, estimates that the time span during which volatility would revert half way back to its unconditional mean would be approximately 0.79 days.

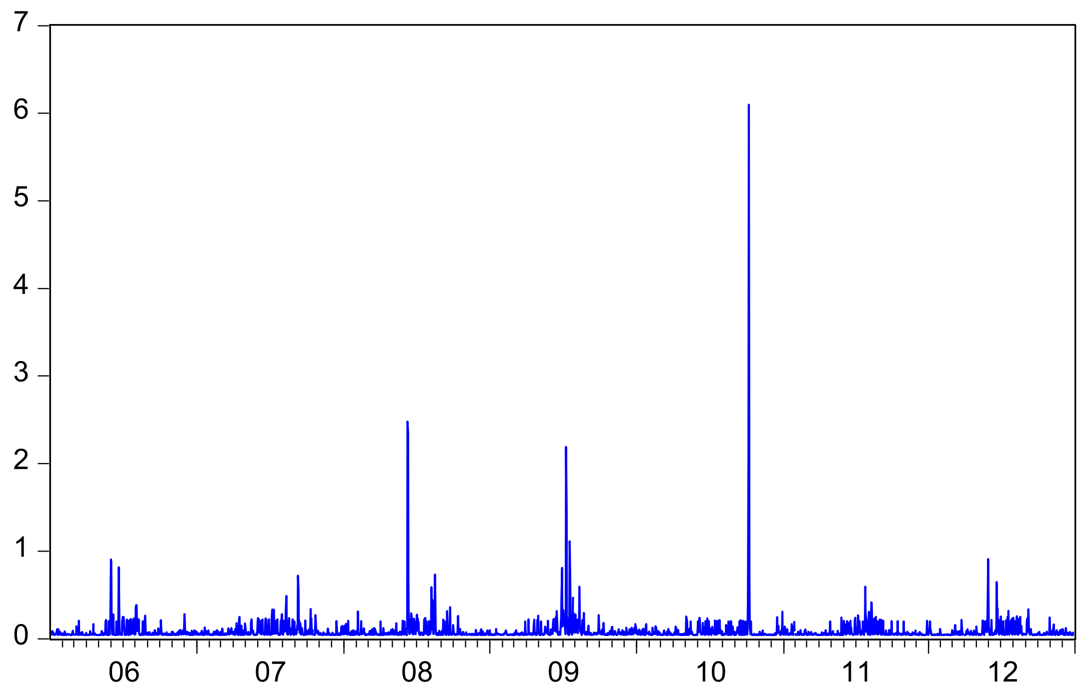

Figure 4.4: Conditional Variance of NYISO Capital Zone RT Price Volatility
Thunderstorm Alerts (*TSA*)
January 2, 2006 – December 31, 2012

CHAPTER 5

Conclusion

5.1 Summary of Findings

The analytical models used herein found the three indentified market deployments executed by NYISO have been associated with a successful reduction in price volatility. This characteristic holds true following the prohibition of circuitous bid scheduling around Lake Erie, mitigation put in place to resolve the Lake Erie Loop Flow issue and the resultant congestion that produced market fluctuations and uplift charges. In addition, there was an associated reduction in price volatility with the establishment of a centralized wind forecasting system that provided NYISO with a more accurate prediction of energy output produced by wind resources. Finally, this association was characteristic of the incorporation of wind resources in NYISO's economic dispatch in order to help resolve the issue of system constraints resultant of concentrated but intermittent energy generation.

This study also explored the impact of the anticipatory announcement of Thunderstorm Alerts (TSAs) on price volatility. Preparation after the issuance of a TSA requires generation start-up in New York City; typically, start-up costs in conjunction with line congestion due to operational measures highly impact electricity prices. When analyzed as an explanatory variable within the GARCH model, there was an associated increase in price volatility. The effect of a TSA event on volatility compared to the implementation of the three volatility-reduction policies was over four times greater in magnitude.

5.2 Policy Implications

As the United States and New York State move farther into the era of deregulated electricity markets, the twin goals of efficiency and reliability remain important and worthy of research. Numerous studies have been conducted on price volatility in markets around the world; these have included, but have certainly not been limited to, modeling the markets of England and Wales (Tashpulatov, 2011); Spain, California, UK, and PJM (Benini, et al., 2002); and Australia (Thomas and Mitchell, 2007). However, very few studies had been conducted on the New York markets thus far, the primary source for this document being the analysis of Hadsell (2007) on virtual bidding. This study revealed the successful reduction in price volatility associated with a number of specific policies within the Capital Zone. Frequently, new market mechanisms are enacted with the belief that they will improve the market, but the results are rarely assessed adequately. Studies like these support continued research into the post-effects of market design measure implementations, where both positive outcomes as well as potential negative market responses may occur; post-execution studies ensure fine-tuning and perhaps even policy-reversal efforts are implemented in timely manner.

Explanatory variables included in this particular study lend support for continued analysis of the current market design. The Lake Erie Loop Flow response provides support to the importance of market monitoring and mitigation efforts. Market participants, though acquitted of any charges of market manipulation or tariff violation by FERC, were certainly taking advantage of pricing knowledge for profit purposes (Clamp, 2010). While this particular loop flow was corrected through NYISO's circuitous prohibition measures, the organization also implemented "rigorous monitoring procedures to provide transparency and to better address congestion costs," which included "a daily review of market outcomes to identify unusual or unexpected market outcomes to identify the root-cause source of certain uplift and other marketplace costs" (Clamp, 2010). Undeniably, constant and meticulous monitoring of the markets is required to maintain a state of equilibrium. Studies like this one address the benefits of market monitoring to general market welfare; while it was determined that uplift charges were reduced, this policy was associated with an additional overall reduction in price volatility.

Accurate forecasting is an extremely important aspect of market operations, and this study supports advancements both in terms of weather and load. First and foremost is the consideration of uncontrollable but oftentimes-predictable natural occurrences. If the market is prepared for these events through accurate forecasting efforts, the impacts may be somewhat alleviated. TSAs allow the market to ramp up generation in preparation of potential line outages; implementation of these events undoubtedly helps reduce drastic price fluctuations that would occur if reliability of the system was threatened. While it is important to understand that the announcement of a TSA will cause temporary volatility in the markets, accurate forecasting allows market participants to prepare for both requests for additional generation as well as expected price fluctuations consequential of a TSA.

Forecasting weather comes into effect with regards to wind resources as well. This study found that providing detailed information to NYISO for maintenance of a centralized wind forecasting system facilitated improved forecasting of energy production by wind resources. Further enhancements were made with the full incorporation of wind resources into the economic dispatching system. Both of these measures taken to improve the reliability of this renewable energy source on the transmission system helped alleviate price volatility in the markets.

Green energy appears destined to play a growing role in the future of electricity markets. However, the nature of this power production is quite unique, such that generation is often intermittent and clustered in areas favorable to the source of energy. Careful and continuous analysis should be taken before and after the assimilation of renewable energy resources to ensure optimized integration into the electricity markets and continued transmission system reliability.

5.3 Suggestions for Further Research

The modeling of this paper was successful in documenting the impact of these variables on price volatility. Nevertheless, there are certainly areas for further research as well as some shortcomings of the current research that should be discussed.

First and foremost, expansion of data to include all zones of the New York Control Area would be advantageous in understanding both the impact of the analyzed factors within each additional zone as well as the their more general, market-wide effect. This study focused on market information exclusively related to NYISO's Capital Zone. This is only one of eleven zones in the New York transmission system, and as such, provides only one view of the data. Logically, it seems unlikely that there would be a price volatility effect reversal of any of the four analyzed variables; this is supported by the results of Hadsell (2007), who determined that virtual bidding was associated with a statistically significant reduction in RT price volatility in all zones, excluding the Long Island Zone. However, while the four explanatory variables analyzed herein may not reverse their impact on price volatility, the magnitude of the effect of each may vary in different regions of the state.

In terms of the variables analyzed herein, it may happen that the Lake Erie Loop Flow variable has more impact on zones in the western region of the state bordering this lake where congestion may have concentrated; therefore, while the variables certainly show effect on volatility in the Capital Zone, the associated coefficient in the West could be notably higher. In continuation of location-based analysis, the concentrated presence of wind generation in the northern and western regions of the state (Figure 3.2) may cause interesting effects on the magnitude of the *WIND* and *WIND_FRCST* variable coefficients specific to these zones as well (Yeomans, 2010). Typically, these areas will have characteristically lower prices with the existence of congestion in the system, inhibiting the easy movement of this generation to demand-intensive locations (Hausman et al., 2006, 4). Volatility may already be reduced due to the excessive supply of generation and therefore these variables may have less effect. Conversely, forecasting and economic dispatch of these resources could enable smoother transfers of energy across constraints; these variables could, in turn, have the same or greater effect as they held in the Capital Zone. In both instances, limiting the scope of the study to the Capital Zone has inhibited an understanding of the broader market spectrum. Expansion of zonal data for this study will confirm each variable has the same associated effect across the state and will be more useful for a market-wide analysis of the events.

This data expansion would have the additional benefit of resolving the issue regarding the removal of twenty-three dates and associated data due to their lack of usable data. Any time data must be removed, there is an assumed effect of some magnitude on the results of the analysis. Fortunately, this data set is expansive, with seven years of hourly data converted to daily averages, producing 2,557 unique data points; the elimination of twenty-three points removes only 0.9% of the original data. Therefore, the effect from the removal of these dates is presumed to be minimal.

While cross-sectional data expansion is indeed important, it would be beneficial to expand the time span of the study as well. The implementation of Standard Market Design (SMD2) on February 1, 2005 was arguably the most crucial development in the New York markets to date (NYISO, 2005, 1). Analyzing the associated impact of this market change on price volatility would be exceedingly valuable and would require an expanded time span of data. However, keep in mind that it may be crucial to impose time span constraints when analyzing individual market adjustments and policies, based on their unique implementation dates. The drastic market changes that occurred as a result of SMD2 severely altered the data prior to and after this date; using a dataset spanning this marker may reflect less the impact of the explanatory variable and more the overwhelming effect of SMD2. Dependent upon the relative deployment date of the analyzed policy, limiting data to before or after the SMD2 implementation date may become crucial.

Further investigation of additional market implementations as well as adverse conditions like TSAs and their effects on price volatility in NYISO markets would be useful to understand what impacts the system and where further investigation and efforts should be focused. Relating directly to this study, there was an adjustment made to the centralized wind forecasting system in 2010. From that point forward, wind resource participants were obligated to provide meteorological data for a five-kilometer radius around each turbine at a constant thirty-second stream of data for NYISO's forecasting efforts (Yeomans, 2010). Whether this adjustment was beneficial in terms of price volatility would be a useful focus of analysis. Not only would it show the benefit of wind forecasting, it would also indicate the value of continued analysis and fine-tuning of already-executed market implementations. Furthermore, additional analysis conducted on renewable energy sources is extremely valuable as the electricity industry moves steadily forward in its efforts to research and incorporate additional sources of green technology.

While analyzing the impact of the implementation of certain market mechanisms has its benefits in determining the successes and failures of these policies, approaching the issue of price volatility from a different angle may provide even greater insight into this issue. This study began by researching policies and modeling their impact on price volatility; an alternative approach would be to identify periods of less volatility and attempt to uncover the trigger that sparked this reduction. This may be an appropriate way to uncover the mechanisms that caused the periods of relative calm that can be seen in the graph of the return series of prices in Figure 3.1. Noteworthy of this figure as well are the distinct periods of high volatility. This methodological approach could also be used to research the causes of these extreme price fluctuation episodes.

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APPENDIX A

Data

Table 3.1: Descriptive Statistics of Variables
January 2, 2006 – December 31, 2012

Variable	Mean	Standard Deviation	Maximum	Minimum	Observations[5]
Dependent Variable					
P_RS	0.0008	0.3174	4.3782	-2.8266	2534
Exogenous Variables					
LOAD	1311.956	159.2651	159.2651	921.1958	2534
FRCST	1271.602	152.1447	152.1447	917.1667	2534
CONG_AVG	-12.0989	24.0556	24.0556	-260.93	2534
Explanatory Variables					
LE08	0.6342	0.4818	1	0	2534
WIND_FRCST	0.6476	0.4778	1	0	2534
WIND	0.5193	0.4997	1	0	2534
TSA	0.0837	0.2769	1	0	2534

[5] This figure does not include the following dates due to negative average prices, resulting in an incalculable daily return series value, and/or missing forecasting and/or TSA data: 1/1/06; 7/1/06; 7/2/06; 10/16/07; 3/1/08; 5/21/08; 7/23/08; 7/24/08; 11/1/08; 7/26/09; 7/27/09; 9/5/10; 1/26/11; 1/30/11; 1/31/11; 8/28/11; 8/29/11; 11/6/11; 11/7/11; 1/26/12; 1/27/12; 3/30/12; 5/24/12. For more detail, please reference Chapter 3: Econometric Technique and Analytical Approach.

APPENDIX B

Regression Estimations

Table 4.1: NYISO Capital Zone RT Price Volatility and Lake Erie Loop Flow Mitigation
January 2, 2006 – December 31, 2012

Variable/Coefficient		Coefficient Value	Standard Error	Significance (p-stat)	Calculated Term	Calculated Value
Mean Equation						
LOAD	λ_1	0.0009	0.0001	** 0.0000		
FRCST	λ_2	-0.0008	0.0001	** 0.0000		
CONG_AVG	λ_3	-0.0014	0.0001	** 0.0000		
Variance Equation						
Constant	ω	0.0154	0.0009	** 0.0000	$(\alpha+\beta)$	0.8740
LE08	γ	-0.0034	0.0010	** 0.0006	Half-Life	5.1475
ARCH (ε^2_{t-1})	α	0.2610	0.0156	** 0.0000		
GARCH (σ^2_{t-1})	β	0.6130	0.0121	** 0.0000		

Effective Date of *LE08*: July 22, 2008
Number of Observations: 2,534[6]
** Statistically significant at 1%
* Statistically significant at 10%

[6] This figure does not include the following dates due to negative average prices, resulting in an incalculable daily return series value, and/or missing forecasting and/or TSA data: 1/1/06; 7/1/06; 7/2/06; 10/16/07; 3/1/08; 5/21/08; 7/23/08; 7/24/08; 11/1/08; 7/26/09; 7/27/09; 9/5/10; 1/26/11; 1/30/11; 1/31/11; 8/28/11; 8/29/11; 11/6/11; 11/7/11; 1/26/12; 1/27/12; 3/30/12; 5/24/12. For more detail, please reference Chapter 3: Econometric Technique and Analytical Approach.

Table 4.2: NYISO Capital Zone RT Price Volatility and Wind Forecasting
January 2, 2006 – December 31, 2012

Variable/Coefficient		Coefficient Value	Standard Error	Significance (p-stat)	Calculated Term	Calculated Value
Mean Equation						
LOAD	λ_1	0.0013	0.0001	** 0.0000		
FRCST	λ_2	-0.0013	0.0001	** 0.0000		
CONG_AVG	λ_3	-0.0009	0.0001	** 0.0000		
Variance Equation						
Constant	ω	0.0155	0.0009	** 0.0000	$(\alpha+\beta)$	0.8744
WIND_FRCST	γ	-0.0035	0.0010	** 0.0004	Half-Life	5.1644
ARCH (ε^2_{t-1})	α	0.2608	0.0156	** 0.0000		
GARCH (σ^2_{t-1})	β	0.6136	0.0121	** 0.0000		

Effective Date of *WIND_FRCST*: June 18, 2008
Number of Observations: 2,534[7]
** Statistically significant at 1%
* Statistically significant at 10%

[7] This figure does not include the following dates due to negative average prices, resulting in an incalculable daily return series value, and/or missing forecasting and/or TSA data: 1/1/06; 7/1/06; 7/2/06; 10/16/07; 3/1/08; 5/21/08; 7/23/08; 7/24/08; 11/1/08; 7/26/09; 7/27/09; 9/5/10; 1/26/11; 1/30/11; 1/31/11; 8/28/11; 8/29/11; 11/6/11; 11/7/11; 1/26/12; 1/27/12; 3/30/12; 5/24/12. For more detail, please reference Chapter 3: Econometric Technique and Analytical Approach.

Table 4.3: NYISO Capital Zone RT Price Volatility and Economic Dispatch of Wind Resources
January 2, 2006 – December 31, 2012

Variable/Coefficient		Coefficient Value	Standard Error	Significance (p-stat)	Calculated Term	Calculated Value
Mean Equation						
LOAD	λ_1	0.0014	0.0001	** 0.0000		
FRCST	λ_2	-0.0013	0.0001	** 0.0000		
CONG_AVG	λ_3	-0.0008	0.0001	** 0.0000		
Variance Equation						
Constant	ω	0.0146	0.0008	** 0.0000	$(\alpha+\beta)$	0.8682
WIND	γ	-0.0034	0.0010	* 0.0827	Half-Life	4.9049
ARCH (ε^2_{t-1})	α	0.2644	0.0156	** 0.0000		
GARCH (σ^2_{t-1})	β	0.6038	0.0122	** 0.0000		

Effective Date of *WIND*: May 12, 2009
Number of Observations: 2,534[8]
** Statistically significant at 1%
* Statistically significant at 10%

[8] This figure does not include the following dates due to negative average prices, resulting in an incalculable daily return series value, and/or missing forecasting and/or TSA data: 1/1/06; 7/1/06; 7/2/06; 10/16/07; 3/1/08; 5/21/08; 7/23/08; 7/24/08; 11/1/08; 7/26/09; 7/27/09; 9/5/10; 1/26/11; 1/30/11; 1/31/11; 8/28/11; 8/29/11; 11/6/11; 11/7/11; 1/26/12; 1/27/12; 3/30/12; 5/24/12. For more detail, please reference Chapter 3: Econometric Technique and Analytical Approach.

Table 4.4: NYISO Capital Zone RT Price Volatility and Thunderstorm Alerts
January 2, 2006 – December 31, 2012

Variable/Coefficient		Coefficient Value	Standard Error	Significance (p-stat)	Calculated Term	Calculated Value
Mean Equation						
LOAD	λ_1	0.0009	0.0001	** 0.0000		
FRCST	λ_2	-0.0008	0.0001	** 0.0000		
CONG_AVG	λ_3	-0.0014	0.0002	** 0.0000		
Variance Equation						
Constant	ω	0.03734	0.0021	** 0.0000	$(\alpha+\beta)$	0.4154
TSA	γ	0.1562	0.0087	** 0.0000	Half-Life	0.7891
ARCH (ε^2_{t-1})	α	0.2985	0.0223	** 0.0000		
GARCH (σ^2_{t-1})	β	0.1170	0.0274	** 0.0000		

Number of Observations: 2,534[9]
** Statistically significant at 1%
* Statistically significant at 10%

[9] This figure does not include the following dates due to negative average prices, resulting in an incalculable daily return series value, and/or missing forecasting and/or TSA data: 1/1/06; 7/1/06; 7/2/06; 10/16/07; 3/1/08; 5/21/08; 7/23/08; 7/24/08; 11/1/08; 7/26/09; 7/27/09; 9/5/10; 1/26/11; 1/30/11; 1/31/11; 8/28/11; 8/29/11; 11/6/11; 11/7/11; 1/26/12; 1/27/12; 3/30/12; 5/24/12. For more detail, please reference Chapter 3: Econometric Technique and Analytical Approach.