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Assessing the Impact of Economically Dispatchable Wind Resources on the New England Wholesale Electricity Market

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ASSESSING THE IMPACT OF ECONOMICALLY DISPATCHABLE WIND RESOURCES ON THE NEW ENGLAND WHOLESALE ELECTRICITY MARKET

A Thesis Presented

By

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ABSTRACT

ASSESSING THE IMPACT OF ECONOMICALLY DISPATCHABLE WIND RESOURCES ON THE NEW ENGLAND WHOLESALE ELECTRICITY MARKET

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Among renewable energy resources, wind power is poised to contribute most significantly to meeting future wholesale electricity demand. However, the intermittent nature of wind power makes maintaining system reliability a challenge as the share of installed wind capacity on the grid increases. In New England, wind plants are currently unable to receive automatic dispatch instructions from the regional grid operator, but a centralized wind forecasting system under development will enable wind plants to be dispatched by ISO New England's automatic dispatch software by 2016. Wind plants will receive an upper bound to their production through so-called Do Not Exceed (DNE) dispatch limits. This study evaluates how the automatic dispatch of wind plants in the ISO New England control area will impact wind plant output, emissions, wholesale energy market prices, and the system-wide generation mix.

Wind generation is modeled using 10-minute time-series wind speed data from the National Renewable Energy Laboratory's Eastern Wind Dataset. Market outcomes for 2020 are then simulated using the spreadsheet-based Oak Ridge Competitive Electricity Dispatch (ORCED) model which mimics the economic dispatch of power plants in deregulated wholesale electricity markets. Results show that imposing DNE dispatch limits reduce total wind generation by a small amount – 6.47% over the course of the study year. The study finds that DNE dispatch limits constrain wind generation often – 28.4% of the year on average – but that the levels of wind generation avoided were typically small – 72.4% of DNE limit curtailment events were at levels below 5% of plant nameplate capacity.

Keywords: Wind, wholesale electricity markets, Oak Ridge Competitive Dispatch (ORCED) model, Do Not Exceed dispatch

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GLOSSARY

AEO – Annual Energy Outlook

DIR – Dispatchable Intermittent Resource

DNE – Do Not Exceed (Dispatch Limit)

EIA – Energy Information Administration

EWD – Eastern Wind Dataset

FCA – Forward Capacity Auction

FERC – Federal Energy Regulatory Committee

GW – Gigawatt (1,000,000,000 watts)

ISO – Independent System Operator

KW – Kilowatt (1,000 watts)

LDC – Load Duration Curve

MISO – Midwest Independent System Operator

MISO – Midwest Independent System Operator

MW – Megawatt (1,000,000 watts)

NEMS – National Energy Modeling System

NEWIS – New England Wind Integration Study

ORCED – Oak Ridge Competitive Electric Dispatch (Model)

PTC – Production Tax Credit

REC – Renewable Energy Credit

RPS – Renewable Portfolio Standard

RTO – Regional Transmission Organization

TW – Terawatt (1,000,000,000,000 watts)

CHAPTER 1

WIND POWER AND THE ELECTRIC GRID

1.1 Introduction

Wind energy is experiencing a period of rapid growth in the United States. In a time where concern is building over fossil fuel emissions and climate change, wind offers an emissions-free alternative. Furthermore, an increasingly diversified generation mix that contains a higher share of wind provides a valuable hedge against volatility in the price of natural gas and electricity (Bolinger and Wiser 2009). This point is especially relevant in systems largely dependent on natural gas for electricity production such as New England, where pipeline constraints and residential heating demands driven by periods of cold weather often result in significant price increases during winter months (EIA 2013). Greater turbine efficiency driven by technological advancements, federal tax incentives, and subsidies related to state renewable energy targets, have helped drive down the cost of wind power relative to other generation sources. Because of these factors wind plants are now able to compete with conventional thermal generators in electricity markets across the country. While critics correctly point out that a rapid adoption of intermittent renewables can pose a threat to grid reliability, the shift toward utility-scale production from wind and solar will continue unabated. New England has excellent wind potential, and as of January 1, 2013 nearly a third of planned capacity additions in the region were from wind plant projects (ISO New England 2013b).

With wind plants economically viable and expanding in many areas, the challenge becomes integrating these intermittent resources into an electrical grid not equipped to manage them. Wind speeds, and by extension plant output, are a function of complex meteorological processes that are difficult to predict in the long-term. Over the short-term though, five-to-ten minutes into the future, wind plant output can be estimated fairly accurately using simple forecasting methods (Brower 2011). Without accurate short-term forecasts the cost of delivering electricity to the grid becomes increasingly expensive as the level of wind penetration rises. System reserve requirements, whose costs are born by all ratepayers, must be increased to handle the variability in wind output. System operators, having no knowledge of future wind output, are forced to curtail wind resources in order to maintain system reliability. Wind plant managers, lacking the ability to store electricity, must pitch turbine blades thereby forgoing potential electricity market revenues. The greatest variable cost for thermal generating units are their fuel inputs, so when they receive curtailment instructions from the grid operator and are forced to forgo energy revenues it has a less pronounced effect on the economics of the plant. Wind on the other hand pays no fuel costs, the operations and maintenance costs are relatively low, and in many jurisdictions wind plants receive a subsidy for each megawatt (MW) of energy they deliver to the grid in the form of Renewable Energy Credits (RECs). The inefficient use of wind power results in the wind plant operator losing significant energy market revenues and the system bearing higher costs of energy by not dispatching a plant with a zero marginal cost.

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) that administer regional electricity markets sensitive to these grid reliability and system efficiency concerns, have taken steps to adjust market rules in order to accommodate the growing share of wind capacity. The New England grid operator, ISO

New England, is the last remaining ISO or RTO in the United States without a centralized wind forecasting system (Rogers and Porter 2011). A short-term centralized forecasting system allows wind resources to receive automatic dispatch instructions in the form of 'Do Not Exceed' (DNE) dispatch limits, which effectively set an upper bound output limit for each individual wind plant on the grid. Under the current system wind plants are classified as self-scheduled generators, meaning they deliver as much electricity to the grid as they can unless the grid operator manually contacts the plant to instruct the resource to limit output based on system conditions. ISO-NE plans to introduce centralized wind forecasting by the end of 2013, and beginning in 2015 or 2016 wind resources will start to receive automated DNE dispatch limits (Lowell 2012).

The integration of wind energy into the New England grid is a complex issue that has become a regional priority. With wind dispatched according to DNE limits, the system will potentially reduce wind curtailments, be able to respond to changing weather conditions more readily, and send the appropriate price signals to generators when wind does get curtailed. Simulating future scenarios in which wind plants are managed using DNE dispatch limits will be helpful in understanding how emissions levels and energy market prices may respond in the period after the market rule changes occur. This study builds on the work carried out in the New England Wind Integration Study (NEWIS) which was commissioned by ISO-NE to assess the operational effects of large-scale wind integration, and adds to that study by focusing specifically on the change in economic and environmental outcomes between scenarios in which wind plants produce at maximum output and scenarios in which there is an upper bound to output imposed by DNE dispatch limits.

1.2 Objectives

This study sets out to answer two questions associated with the transition to a wholesale electricity market with automatic wind plant dispatch using DNE dispatch limits. The first objective is to quantify the impacts of DNE limits on wind energy generation in a system where no wind curtailment is assumed. Annual electricity generation in 2020 is calculated for wind plants dispatched manually, as they are currently in New England, and for wind plants dispatched by automatic DNE limits. The expected difference in electricity generation between these two dispatch regimes is then quantified. The second objective is to quantify how that difference in annual electricity generation from wind plants affects emission rates, the generation mix, and energy market prices in New England.

Data on wind speed and wind plant capacity is used to address the first objective. To approach the second objective, a model of the wholesale electricity market in New England is used to simulate competitive power plant dispatch and calculate market outcomes for 2020.

The comparison of dispatch regimes outlined by the objectives is framed in three scenarios representing potential 2020 levels of installed wind capacity in New England. At increasing levels of installed wind capacity, the difference between wind plant generation in the two dispatch regimes will have non-linear effects on emission rates, the generation mix, and wholesale energy prices.

Three levels of installed wind capacity are modeled in the study. The level of installed wind capacity in the Low scenario is equal to the sum of wind plant capacity from currently operational wind plants and proposed wind plants in the ISO New England interconnection queue as of January 1st, 2013. Installed wind capacity increases from scenario to scenario linearly. That is, the installed wind capacity in the Low scenario is increased by 100% to arrive at the level of installed wind capacity in the Medium scenario, and 200% to arrive at the level of installed wind capacity in the High scenario. Defining installed wind capacity in this way allows the identification of any non-linear effects of dispatch regime change on the market outcomes outlined in the second objective.

The Low case includes those wind plants in New England that are currently operating or have applied for interconnection, totaling 3.25 gigawatts (GW) of installed capacity. In the Medium and High scenarios, installed wind capacity equals 6.5 GW and 9.75 GW respectively.

Results indicate that wind generation is impacted only slightly by the implementation of DNE limit dispatch. Wind generation only decreases by 6.47% over the course of the study year after DNE limits are introduced. Given that the study assumes no wind curtailment due to transmission constraints or wind forecast uncertainty in the period before DNE dispatch implementation, which is unlikely in reality, the decrease in wind generation found here is likely an overestimate of the true effect. The corresponding effects on regional emissions and wholesale electricity prices are also found to be unsubstantial.

Furthermore, although wind plants have their generation constrained by DNE limits often – 28.47% of the season on average – the amounts of potential generation avoided is generally small, with only 3.3% of curtailment events occurring at levels above 15% of plant nameplate capacity. The findings show that implementing DNE limits will have minimal effects on the ability of wind plants to produce energy, and will in all likelihood provide meaningful financial benefits to wind plants contingent on current levels of wind curtailment that will be alleviated by DNE dispatch.

1.3 Thesis Outline

The remaining chapters of this thesis are organized as follows. Background on the New England wholesale electricity markets and wind power technology is provided in Chapter 2, and the contributions of this study to the literature on wind plant grid integration is established. Chapter 3 describes the data and modeling inputs used, including the method by which wind plant output is estimated. Chapter 4 outlines the model used to simulate competitive generator dispatch in the New England wholesale electricity market. Results from modeled annual outcomes of the wholesale electricity market in 2020 under the study scenarios are presented in Chapter 5. Finally, Chapter 6 provides a discussion of the results and points to viable extensions of this research.

CHAPTER 2

BACKGROUND AND LITERATURE REVIEW

2.1 The New England Wholesale Electricity Market

New England electricity markets have been integrated to some extent since 1971 when the New England Power Pool was formed in reaction to the 1965 Northeast Blackout. The major structural change occurred during the late 1990s, when wholesale electricity markets in the United States began undergoing deregulation. Vertically integrated electric utilities once regulated by Public Utilities Commissions were dissolved and competition was introduced, primarily on the generation side. ISO New England is a not-for-profit organization that was created in 1997 by the Federal Energy Regulatory Committee (FERC) to help transition the regional wholesale electricity market through deregulation. Today ISO New England administers the wholesale electricity markets, manages the high-voltage transmission system on behalf of market participants, and ensures competitive balance through regulatory activity.

For several years ISO New England acted as something of a consultant to stakeholders in the region, primarily implementing market designs and changes that participants decided upon. That changed in 2003 when FERC changed ISO New England's status to that of an RTO, which conferred on it the directive to take a leadership role in crafting market design and oversight. ISO New England cannot unilaterally change market rules, nor can it discipline market participants. If an investigation by the ISO determines that a participant has violated a market rule they must refer them to FERC which exclusively can determine penalties. The ISO itself answers to FERC, and both an internal and external market monitor exist to observe the organization's behavior.

The New England power system serves 6.5 million households and businesses, supporting a population of 14 million people. Over 300 generators provide roughly 32,000 megawatts (MW) of total supply, and the system all-time peak demand of 28,130 MW was set on August 2, 2006. ISO New England facilitates the dispatch of electricity for Vermont, New Hampshire, Maine, Massachusetts, Rhode Island and Connecticut on 8,000 miles of high-voltage transmission lines. The system is interconnected to the New York, Quebec, and New Brunswick grids (Brandien and Rourke 2011).

All generators in the region, including several participants from Canada and New York, submit daily supply offers for each of their available generating units. ISO-NE then schedules these units to meet the real-time power needs of New England. By way of the "merit order" process, the next cheapest generator delivers the marginal unit of energy to the grid as transmission constraints and reserve requirements allow (van Welie 2005). The wholesale electricity market at large is actually comprised of three distinct markets; one for each energy, for capacity, and for reserves and ancillary services such as voltage control.

The energy market itself is a multi-settlement system, meaning there is a day-ahead and real-time component. In the simplest terms, the ISO takes all the supply offers and demand bids from the day-ahead market and intersects the derived supply and demand curves to find the energy market clearing prices for each hour of the day in each sub-region in the day-ahead unit commitment process (van Welie 2005). Price discovery occurs in the day-ahead market. Minute-to-minute regional power needs are then balanced in the real-time market.

Electricity markets are unique from an economic perspective because they depend as much on the laws of physics as they do on the forces of supply and demand. Every five minutes at the ISO New England facility computers solve a linear programming problem that considers rapidly changing physical conditions on the grid in addition to demand and generator availability.

2.2 Wind Resources

Total energy production costs from different forms of generation are often compared using levelized energy cost analysis, in which the net present value of future costs related to capital investments, fuel costs, and operations costs, are calculated according to the time value of money. In 2012-2013 the levelized cost of wind energy in the U.S. was estimated to be at an all-time low of $40/MW, and it is projected to decrease 25% further by 2030 (Wiser and Lantz 2012).

Effects from rising capital costs have been offset by improvements in turbine and blade technology, making wind plants more efficient in geographic locations with historically sub-optimal wind resources (Wiser and Lantz 2012). Federal incentives and state renewable energy policies are playing an even larger role in reducing the cost of wind energy. As wind developers rush to meet RPS targets there are signs that some grids are becoming saturated with cheap energy at certain times. In 2011, FERC ruled that the Bonneville Power Administration's curtailment of wind resources in favor of hydropower was discriminatory (Runyon 2011). Without extensive transmission upgrades or advancements in energy storage similar problems will arise.

2.2.1 Policies Driving Wind Adoption

Two major policy developments have fueled the expansion of wind plant construction in the United States in the last decade; the federal renewable electricity production tax credit (PTC) and state renewable portfolio standards (RPS). Initially enacted in 1992, the PTC has been revised and expanded several times since, most recently on January 2, 2013. The credit for wind resources is equal to $0.022/kilowatt hour (kWh), or $22/MWh, and lasts for ten years from the date the facility enters service (DSIRE 2013). Due to the long-term process of permitting and planning utility scale wind projects, uncertainty surrounding the extension of the PTC has been linked to sharp declines in U.S. wind installations (Union of Concerned Scientists 2013).

Twenty-nine states and Washington D.C. have some form of RPS enacted currently. Despite sharing the same policy name, significant heterogeneity exists from one state RPS to the next. RPS policies are implemented as a requirement that relevant firms generate a percentage of their energy supply from renewable sources. This requirement can be thought of in terms of two parts; the terminal percentage goal and the yearly incremental requirements towards that goal. Typically the RPS will be broken into two or more tiers. These represent different requirements for different technologies. In addition, some states give preferential treatment to certain technologies or in-state generation according to unique policy aims. States that permit REC trading often do so in acknowledgement of the fact that renewable generation in-state would be insufficient to meet RPS goals. Judging by the various designs, the RPS policy is motivated by aspirations for economic development as much as environmental concerns.

Table 1. State RPS targets in New England

	Year Passed	*Target Rate*	*Target Year*
Connecticut	2006	20%	2020
Massachusetts	2004	25%	2030
Maine	2008	10%	2017
New Hampshire	2009	12.40%	2025
Rhode Island	2007	14%	2019
Vermont	* No RPS in place - 20% renewable energy goal by 2017		

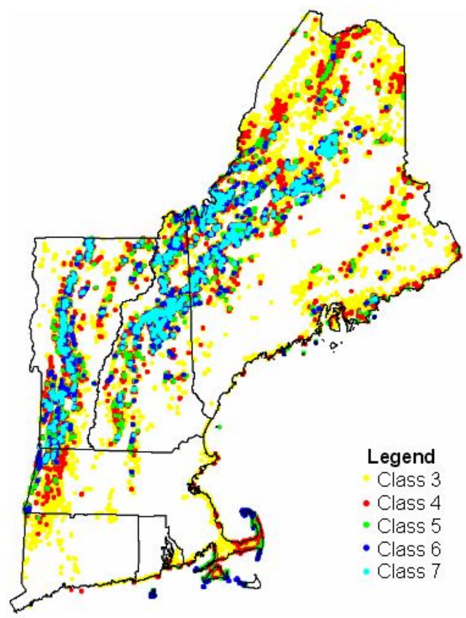
(Source: DSIRE 2013)

Most firms have the option of paying a penalty or alternative payment in lieu of meeting their requirement, and all New England states with a RPS have an alternative payment mechanism in place. This creates an upper bound as to how costly the policy is for firms. A large body of literature exists on the effects of RPS policy on electricity rates, as this was a serious concern for most states during the period when the policy was being debated. Certain states exempt individual firms or entire classes of market participants from the RPS, but in New England the respective RPSs apply to both investor-owned utilities and municipal utilities.

The success of these policies in making utility-scale wind projects economically viable can be seen in transmission interconnection queues around the country. At the end of 2011 there was nearly 220 GW of wind power in U.S. interconnection queues, which was 50% more than the next-largest resource, natural gas (Wiser and Bolinger 2012). Of course all of these resources will not be built, but it shows a pronounced shift in new development from a decade ago.

2.2.2 Wind Energy in New England

In New England there is currently 2583 MW of wind in the interconnection queue, representing 31% of the total capacity. Combined cycle natural gas plants comprise 51% of the total capacity in the queue at 4247 MW (ISO New England 2013b). With wind only representing 3% of total installed capacity in New England today, the amount of wind generation capacity in the queue represents a significant shift. By comparison, the share of natural gas in the queue is roughly equivalent to amount of natural gas generation capacity in operation.

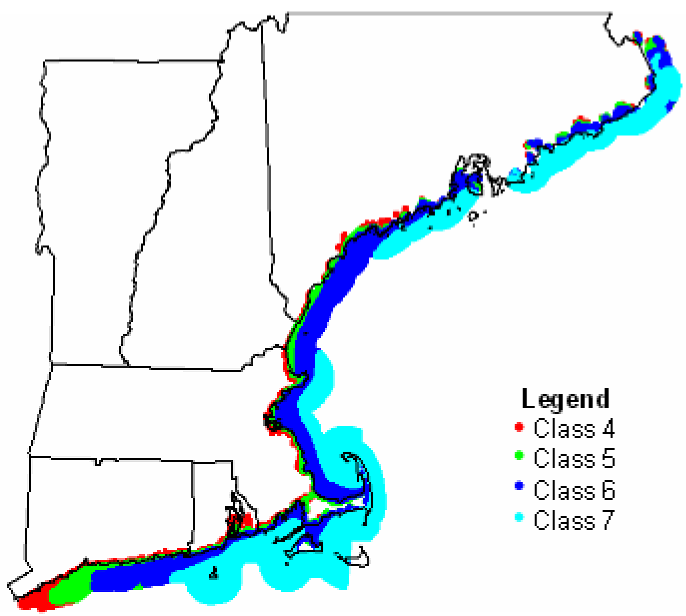


(Source: Levitan & Associates 2007)

Figure 1. New England onshore wind resources

Wind resource potential in the ISO New England control area is not on par with that in the Midwest or Texas but it is significant. Peaking at Class 7, higher wind class ratings indicate the most ideal locations for wind plant operation, and sites with wind speeds that fall below class 3 are generally regarded as unsuitable. The majority of operational and planned wind plants are located in Maine along the Canadian border, and in pockets of Vermont and New Hampshire. Figure 1 shows that the best onshore locations for wind development in New England are far from load centers, meaning extensive transmission upgrades will be required to take full advantage of the region's resources (GE Energy 2010).

Localized congestion is a problem in the region, and overcapacity concerns are causing developers to scale back their proposals in some cases (Rubenstein 2013). For instance, the 99 MW Granite Reliable Power plant in New Hampshire, one of New England's largest wind farms, is attempting to pay Coos County only half of the 2013 property tax payment stipulated in an agreement made in 2008. The plant is contesting payment on the grounds that ISO New England curtailed their output down to 45.835 MW in 2012 and therefore cannot be held fully responsible for smaller than anticipated operation level (Tetrault 2013).



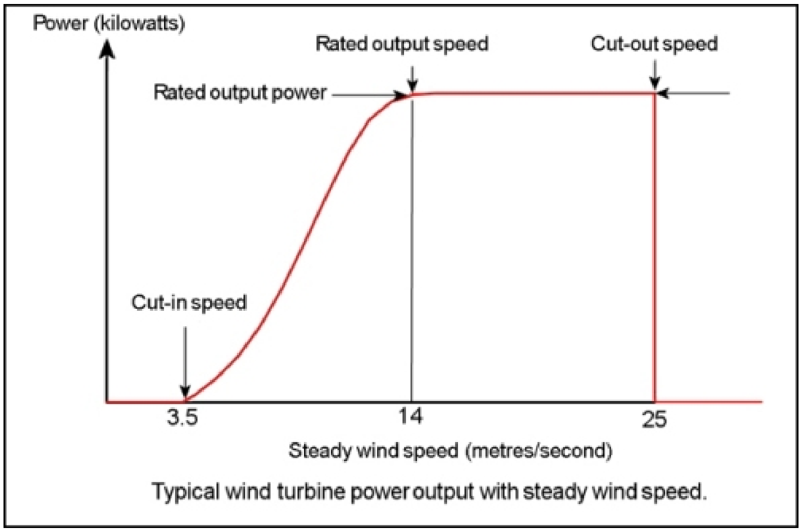
(Source: Levitan & Associates 2007)

Figure 2. New England offshore wind resources

The region possesses exceptional offshore wind resources, which are some of the best and most accessible in the nation. Massachusetts alone has offshore wind resources totaling roughly 200 GW, while the entire region has between 350-400 GW (Schwartz and Heimiller 2010). The ocean depths along the eastern seaboard are shallow compared to those on the west coast due to a large continental shelf, a fact that is conducive to engineering and constructing offshore wind farms. Permitting issues have been a major hurdle for potential developments, as exemplified by the 468 MW Cape Wind project proposed for Nantucket Sound. Originally proposed in 2001, it has been embroiled in constant legal challenges for twelve years. It has finally received final approval and recently signed a $2 billion agreement with the Bank of Tokyo to finance construction beginning in 2013 or 2014, and is poised to be the first offshore wind project in the U.S. (Richardson 2013). With the U.S. Department of the Interior planning to sell leases for two sites on the outer continental shelf in Rhode Island and Virginia, the hope is that a new streamlined development process will result in more offshore wind generation (Smith 2012).

2.3 Integrating Intermittent Resources into the Grid

Wind is a variable source of energy that has a propensity to change rapidly and dramatically. It is driven by complex atmospheric factors, as well as local terrain, which can create extremely disparate wind profiles even at two proximate locations. Integrating wind resources effectively into an electric grid requires sophisticated medium term forecasts and short-term forecasts that rely on second-by-second telemetry data from wind plants. Furthermore, wind turbine power curves - which represent how much electricity a wind turbine can generate as a function of wind speed - are highly non-linear, and small errors in the wind forecast will translate to large errors in forecasted output (Brower 2011).



(Source: The Windpower Project 2013)

Figure 3. Sample wind turbine power curve

The low level of installed wind capacity is one reason there has not been much impetus to develop centralized wind forecasting systems until recently. Data suggests that forecasting becomes essential for effective grid management at wind concentrations above 5% of capacity (Brower 2011). ISO New England, still not at the 5% threshold for installed wind capacity, is implementing a centralized forecasting system before grid management becomes a serious concern. Grid operators in regions with large amounts of installed wind capacity are at the forefront of developing market rules to accommodate intermittent resources. Principal amongst these is the Midwest Independent System Operator (MISO), which has been assigning DNE exceed dispatch to wind plants since 2010. The procedure to determine DNE dispatch limits for wind plants proposed by ISO

New England is analogous to the system developed by MISO, and study adopts the same methodology (Lowell 2012b).

MISO predicts wind output at a particular plant for the period five minutes ahead using the average output of the last twelve five-minute periods (Exeter Associates and GE Energy 2012). This simple technique referred to as ‘persistence forecasting’ is the performance benchmark for short-term (up to an hour ahead) wind forecasts. Despite the enormous investment in wind forecasting since 2000, state-of-the-art hour-ahead forecasts are not much more accurate than hour-ahead persistence forecasts as measured by mean absolute error (Brower 2011). Advanced forecasting models are superior to persistence forecasting methods when predicting day-ahead wind speeds and at identifying wind ramp events that jeopardize system reliability, but in the very short term there is no improvement in forecast performance.

Today wind plants are treated as self-scheduled generators, meaning they produce energy at their own discretion when wind is available. In the absence of accurate forecasting, wind resources cannot be dispatched automatically by unit dispatch software, therefore ISO New England must use manual curtailment procedures. The system operator must physically call the wind plant and give dispatch-down instructions if system reliability is at risk. Manual wind curtailments also tend to be excessive, as system operators must take a conservative approach (Lowell 2012). Critically, when wind generation is curtailed under manual dispatch, wholesale electricity prices on that part of the grid do not separate and reflect the curtailment of resources with low marginal costs. If a wind plant is being curtailed manually, other local generators find an economic incentive to produce more electricity when the system would benefit from those same generators reducing output (Lowell 2012b).

Implementing wind DNE dispatch will minimize wind curtailment, enable operators to more efficiently manage the grid during volatile weather conditions, and align production incentives with efficient market outcomes (Lowell 2012b). Using telemetry data from the wind farm and centralized forecasting, ISO New England will produce an expected wind generation forecast for the next dispatch interval. Additionally, ISO New England will determine the DNE limit based on persistence forecasts, transmission constraints, and offers and operating statuses of the wind plant as well as non-wind plants (Lowell 2012b). The wind plant will have the freedom to operate anywhere beneath the DNE limit as conditions allow. In MISO wind plants are able to exceed the DNE by 8% without being penalized, and nearly all wind plants are able to achieve compliance (Exeter Associates and GE Energy 2012).

2.4 Contributions of this Study

There has been limited research into the implementation of DNE dispatch limits on wholesale electricity markets, and none focused on the New England market. Calculating the change in electricity production from wind plants when transitioning to a market where wind plant production is capped by DNE dispatch limits provides insight into how the rule change will impact the New England electricity markets.

It is important to highlight that the assumption of unconstrained wind plant production, used as a starting point to gauge the effect of implementing DNE dispatch limits, seldom holds in reality. In fact, a primary motivation for introducing DNE dispatch limits is to avoid the excessive curtailment of wind plant production that arises from uncertainty in relation to their short term electricity generation. However, because wind plant operators regard data on the curtailments as highly sensitive and potentially damaging, there is no available information on where and when wind curtailments occur in New England and beyond. Further, assuming levels of curtailments without reliable data is no more tenuous than assuming no wind curtailment, and it could potentially be worse.

The first objective is to quantify how much wind generation is avoided when moving from a manual wind plant dispatch to a dispatch regime where wind plants are given DNE dispatch limits. Initial findings from this first objective will serve as a point of comparison when data on curtailments becomes available in 2014, pending new data that will be collected upon implementing the centralized wind forecast system in New England at the end of 2013. Although relaxing the assumption of no wind curtailment could possibly result in different findings, performing this study can only enhance the understanding of DNE limit wind dispatch.

The second objective is to quantify how the reduction in wind generation realized upon moving to DNE limit dispatch impacts wholesale electricity prices, annual emissions levels, and the generation mix in New England This will shed light on how sensitive the New England wholesale electricity market is to different levels of installed wind capacity. It is important to distinguish between the counteracting effects of increasing the level of installed wind capacity in the three scenarios and the effects of the decrease in electricity generation from wind plants subjected to DNE dispatch limits within each scenario.

For example, the percent of the year certain power plant types spend on the margin may be differ at increasing levels of installed wind capacity. In deregulated wholesale energy markets the clearing price is set by the power plant providing the last MW of electricity to meet demand, otherwise known as the generator on the margin. Power plants offer to supply electricity at variable cost, and all power plants dispatched prior to the marginal generator receive the variable cost of the marginal demand for all the energy they produce in that period.

The amount of curtailed electricity generation from wind plants receiving DNE dispatch limits, relative to those receiving no such instructions, might have a much more significant impact on marginal generators and resulting wholesale electricity prices in the ‘High’ installed wind capacity scenario. At the same time, when just observing wind plant production under DNE dispatch limits, the marginal generators setting price for most of the year in the ‘Medium’ and ‘High’ installed wind capacity scenarios might be very similar.

CHAPTER 3

DATA

3.1 Generating Units

The data on generators used in this study comes from the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) database. NEMS is the source of data for all of the analyses and projections made by the EIA, and as such it is constantly updated and the most comprehensive resource in the public domain. The EIA uses numerous data sources to construct the NEMS database, but the majority of information on generators comes from Form EIA-923. Survey information is collected at the plant and generator level on a monthly basis from approximately 1,900 power plants, and on an annual basis for over 4,100 power plants nationwide (EIA 2012). One power plant can comprise multiple generators, and those generators may burn different fuels. It is not uncommon for one power plant to retire and add individual generators over time.

The Oak Ridge Competitive Electricity Dispatch (ORCED) Model is used to simulate the dispatch of generators to meet New England load demand for this study. ORCED comes loaded with the full database of generators contained in the NEMS dataset from 2011. Both ORCED and NEMS are regional models, breaking the U.S. into study areas based on the National Electric Reliability Council regions. Several generators across the southeastern Connecticut border in New York state that are not in the ISO New England control area are classified in the NEMS data as being in the New England region. These were subsequently removed before analysis.

Data from NEMS is used to sort generators by plant type, fuel type, and variable cost. Once generators are sorted, they are aggregated into representative "power plants" according to their operational characteristics. ORCED does this for computational efficiency, and can accommodate a maximum of 200 of these power plants for use in Dispatch. A more detailed explanation of the Supply module methodology complete with the formula used to calculate generator variable cost is presented in Chapter 4.

Table 2. Variables from NEMS database used for aggregation

Plant ID	Name Plate Capacity	Fuel Code (1, 2, 3)
Unit ID	Summer Capacity	Fuel Share (1, 2, 3)
Plant Name	Winter Capacity	Fixed O&M Cost (87$/kW)
Company ID	Average Heatrate	Variable O&M Cost (87$/MWh
CCAP Index	On-Line Year	Percent sold to Grid
Ownership Type	On-Line Month	NOx Emission Rate (lbs/MBtu)
Must Run Code	Retire Year	Nox Controls Flags
Region Code for Plant Location	Retire Month	NOx Ctrls -- Overnight Cost
State Abbreviation for Plant Location	Status	NOx Ctrls -- Fixed O&M
Census Region Number	Scrubber Efficiency for SO2	NOx Ctrls -- Variable O&M
ZIP Code	Average Capacity Factor	NOx Ctrls -- Reduction Factor
	Monthly Capacity Factor (1-12)	

Fuel data contained in NEMS are used during the initial sorting and aggregation of generators in the Supply module as well. Before the model dispatches generators in the Dispatch module fuel prices can be set to levels expected for the study year, in this case 2020. However, estimating fuel prices seven years into the future is nearly impossible to do with much confidence. Natural gas prices in New England are especially volatile. The region lies at the end of the natural gas pipeline distribution system and over 50% of the electric generation comes from natural gas fired plants. This study assumes the same fuel prices for 2020 as those contained in the NEMS dataset from 2011.

Outage factors refer to times in which a plant will be unavailable for dispatch, for either planned or unexpected reasons. 'Planned' outage factors relate to periods of scheduled maintenance, while ‘forced’ outage factors relate to periods of unplanned unavailability. Outage factors vary from season to season, which is one reason why it is critical that ORCED divides the year into three seasons before dispatching generators to meet annual hourly load.

In addition to the planned retirement dates of generators in the database, NEMS contains assumptions about regional capacity retirements of different plant types through the year 2035. NEMS also projects the amount of unplanned capacity additions required in each region to meet future load growth. Data from the ISO New England interconnection queue support the NEMS projection, but the implicit assumption in the NEMS data is that there will be no new generation built until 2025 (ISO New England 2013b). In contrast, this study simulates scenarios in which there is significant installed wind capacity additions by 2020.

3.2 Wind Plant Production

Time-series data on wind speeds taken from the NREL Eastern Wind Dataset was used to estimate wind plant output. Originally created for the Eastern Wind Integration and Transmission Study, the dataset “contains three years (2004-2006) of 10-minute wind speed and plant output values for 1,326 simulated wind plants as well as next-day, six-hour, and four-hour forecasts for each plant (NREL 2012).” An additional 4,948 sites in the Atlantic Ocean at least 8 km from shore at water depths of no more than 30 m were modeled as well. AWS Truepower, an industry leader in wind forecasting, constructed the dataset using their MASS v.6.8 mesoscale model that has a grid output resolution of 2km.

Wind speeds at each site were combined with a composite turbine power curve to solve for power output at each location after controlling for wind gusts, wake losses, and other factors (NREL 2012). Below a certain ‘cut-in’ speed wind turbines are unable to produce any power, which is typically between 3-4 meters per second. In order to protect mechanical components from strong winds, at a particular ‘cut-out’ speed the turbine ceases to produce any power as well. With wind turbines becoming more efficient and realizing better capacity factors, the Eastern Wind Dataset was updated in June 2012 in part to better reflect future turbine technology.

3.2.1 Hourly Wind Plant Output

In an attempt to capture the most realistic level of output that would be achieved under a full build-out of wind resources in the interconnection queue, latitudinal and longitudinal coordinates of operational and planned wind plants were used to identify proximate sites from the Eastern Wind Dataset. Instead of using the wind plants and output simulated by AWS Truepower’s MASS model directly, the power output for each site was converted to a capacity factor for each 10-minute observation in the time series and then the hourly average was taken. Average hourly capacity factors for each site were then multiplied by the nameplate capacity of the appropriate wind farm to arrive at the power output for that plant’s particular specifications.

$$G_{i,h} = \sum_{t=1}^{6} \{C_i \times (P_{i,t} \div S_i)\} \div 6$$

Where:

$G_{i,h}$ = generation at wind plant i in hour h (MW)

h = hour

t = time periods ending every 10th minute within hour h

C_i = capacity of wind plant i (MW)

$P_{i,t}$ = generation at Eastern Wind Dataset site matched to plant i in time t (MW)

S_i = capacity of Eastern Wind Dataset site matched to wind plant i (MW)

Once the annual hourly electricity generation is calculated for each wind plant the results can be aggregated to arrive at total hourly electricity generation for New England. At that point the data is ready to be fed into the Demand module, where it is subtracted from the escalated hourly load demand for 2020. In the Medium and High scenarios, the wind generation from the Low scenario is simply doubled and tripled, respectively. In all cases daylight savings time was reflected in both the wind output data and the hourly load demand profile it modified.

Wind follows both diurnal and seasonal patterns. Generator output and wind speeds are at their lowest during the summer months, and are at their highest during the winter months. On a daily basis, wind speeds pick up during the nighttime and early morning hours, but the pattern is slightly different during the winter versus the summer. Figure 4 shows the hourly average electricity generation from wind plants in the Low installed wind scenario during January and July, assuming no wind curtailment. In January the wind output starts increasing at 1pm and continues rising through the evening, finally dropping down after midnight. In July, wind output is at its peak between 12am and 6am before dropping down to negligible levels of production from 7am to 4pm, after which it rises slowly through the evening.

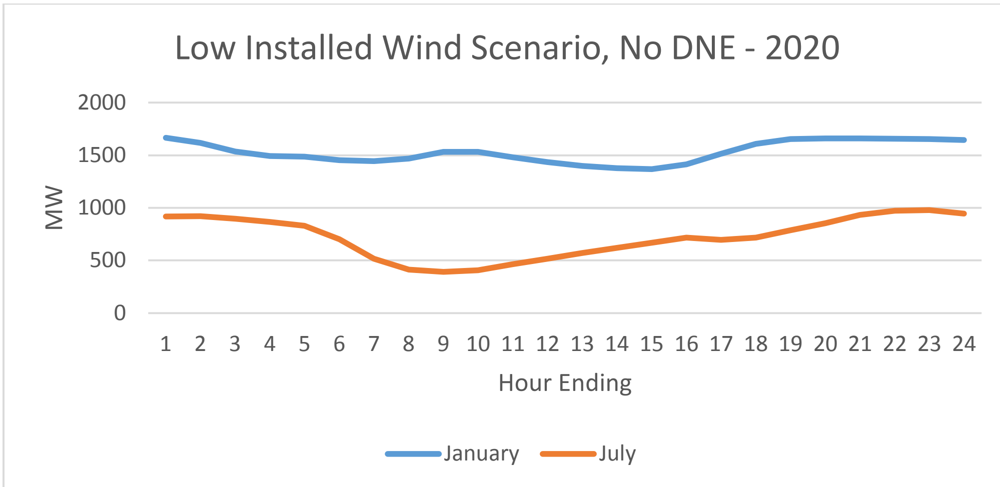
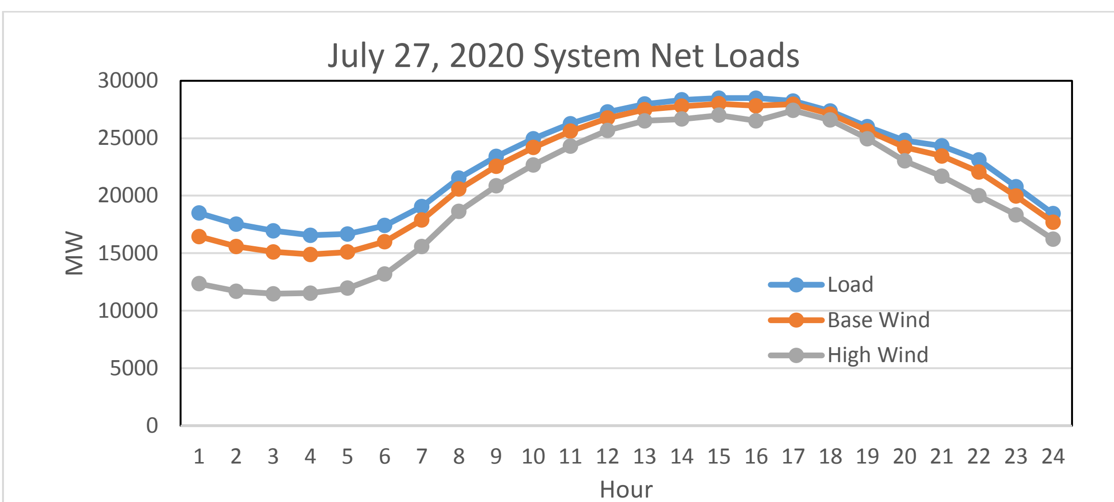


Figure 4. Average hourly wind plant generation in January and July 2020

From a system operator's perspective, it is a problem that wind contributes the least to meeting demand during the most critical times for the system. Net load represents demand on the system that remains after subtracting the contribution from wind generation. Figure 5 compares load demand to net load in the Low-DNE and High-DNE installed wind capacity scenarios on the highest summer demand day in 2020.



(Wind plants subject to DNE dispatch limits)

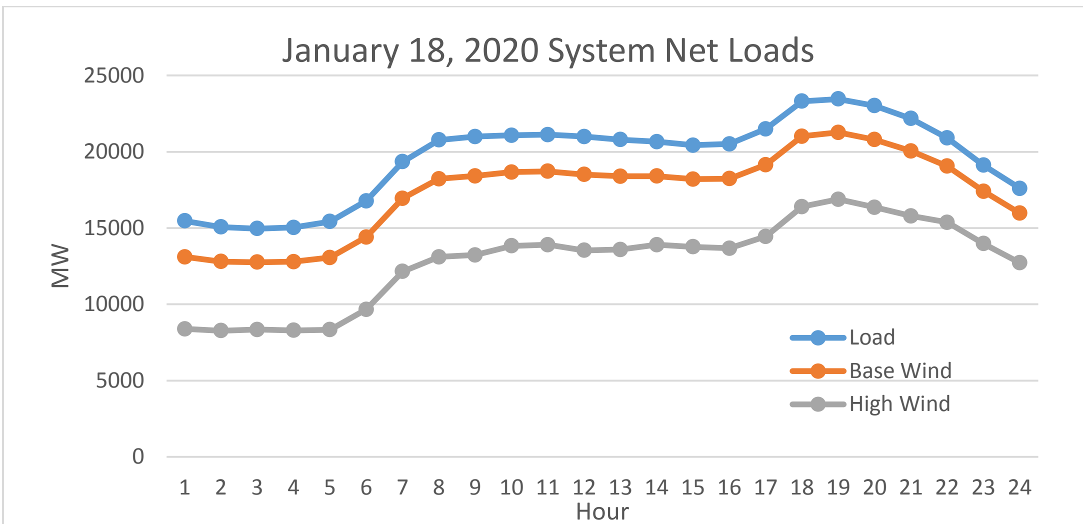
Figure 5. Hourly net loads on 2020 summer peak

The contribution from wind plants toward meeting demand is low, especially during the peak hours. If the wind is not blowing when the grid operator requires the most resources, even endless amounts of installed wind capacity will be unable to displace fossil fuel plants from the generation mix. This highlights an important truth of renewable energy; due to the intermittent and unpredictable nature of energy sources such as wind and the sun, these resources cannot supplant traditional thermal generators on a MW-for-MW basis.

While some fossil fuel peaking plants might only be used for a very small amount of time each year, they are nonetheless indispensable as they provide needed reserves to maintain system reliability. As competition from intermittent generators increases, these peaking plants will see less revenue in the energy market. Capacity and ancillary services markets revenues will be vital in keeping the rarely called upon peaking plants from being mothballed. Due to the dynamic between peaking plants and intermittent generators, the contribution of demand response is seen as essential to flattening seasonal peaks and reducing the power system's reliance on peaking plants to provide reserves (Borlick 2012).

Aggregate wind generation contributes significantly to meeting regional load demand in the winter, notably during the peak hours from 6pm to 8pm. These are the months and hours in which the biggest shift in marginal generators will occur with greater installed wind capacity. Passive demand response contributions will have an additive effect in these months, reducing the amount of load to be served by dispatchable thermal generators even further.

Figure 6 highlights the different story that plays out during the winter and shoulder months from that in the summer. Again total system load demand is compared to system net load under the Low-DNE and High-DNE installed wind capacity scenarios, but on the highest winter load demand day in 2020. On January 18th, electricity generation from wind plants subject to DNE dispatch limits in the Low and High installed wind capacity scenarios reduce peak load demand, from 4pm to 6pm, by 9.6% and 28.8% respectively. In contrast, on July 27th, the projected 2020 peak load day, demand during the peak hours from 2pm to 6pm is only reduced by 1.7% and 5.2% for each scenario.



(Wind plants subject to DNE dispatch limits)

Figure 6. Hourly net loads on 2020 winter peak

3.2.2 Do Not Exceed (DNE) Limits

With hundreds of megawatts of wind capacity installed already, wind power development in the Midwest is at an advanced state by U.S. standards. The grid operator that controls those resources, the Midwest Independent System Operator (MISO), is at the forefront of developing market rules to accommodate the growth of utility-scale wind power. The methodology proposed by ISO New England to set DNE limits for individual wind plants is analogous to that pioneered by MISO, and the same procedure is adhered to in this study.

In November 2010, MISO submitted a filing to FERC that contained their proposal to designate resources as Dispatchable Intermittent Resources (DIRs). A DIR is a resource that is limited by “forecast-dependent fuel availability (Midwest ISO 2010).” The resources in question cannot control the amount of fuel they have access to, but they can control the amount of accessible fuel they use. Therefore a DIR can only be dispatched downward. Prior to the rule change intermittent resources in MISO were treated exactly as they are in ISO New England today. If the dispatcher needed to curtail wind plants downward to manage congestion she would have to manually call instructions into the wind plant (Exeter Associates and GE Energy 2012).

Under the current system in MISO, the DIR submits a Forecast Maximum Limit, which represents the current capability of the plant and serves as the upper limit for dispatch, to the system operator automatically every five minutes. The Forecast Maximum Limit, which is equivalent to the DNE dispatch limit in the ISO New England proposal, is calculated using a rolling persistence forecast of the last twelve 5-minute periods (Exeter Associates and GE Energy 2012). For the purposes of this study, because data on 5-minute output is unavailable, a rolling persistence forecast of the last six 10-minute periods is used instead. The benefit of calculating the DNE dispatch limit in this way is that the current data on hourly wind output can be used to construct the DNE dispatch limit for each plant. MISO accepts DIR production within an 8% ‘tolerance band,’ so wind plants can effectively generate power at up to 108% of their DNE dispatch limit (Exeter Associates and GE Energy 2012). The same custom is adopted for this study.

Table 3. DNE limit calculations for Cape Wind plant

EWD Site Capacity (MW)			20			Site Latitute	43.8492
Reference Site Capacity (MW)			462			Site Longitude	-69.3389
Date	Hour End	Minute	Converted Net Power (MW)	10-Min DNE Limit	Lower Value	Hourly DNE Limit	Hourly Net Power (MW)
20040101	2	10	232.39	101.56	101.56		
20040101	2	20	254.56	135.25	135.25		
20040101	2	30	319.24	169.02	169.02		
20040101	2	40	358.74	209.13	209.13		
20040101	2	50	389.70	247.98	247.98		
20040101	2	60	400.55	288.25	288.25	191.86	325.86
20040101	3	10	415.11	325.86	325.86		
20040101	3	20	411.64	356.32	356.32		
20040101	3	30	413.49	382.50	382.50		
20040101	3	40	414.88	398.21	398.21		
20040101	3	50	413.26	407.56	407.56		
20040101	3	60	398.71	411.49	398.71	378.19	411.18

Table 4 presents the additional steps used to calculate the DNE dispatch limit for an individual wind plant. For each 10-minute period the average of the previous six 10-minute periods is calculated, which produces the simple persistence forecast in 10-minute increments. The lesser of the unconstrained converted net power or the simple persistence forecast, the hypothetical 10-minute DNE dispatch limit, is taken to be the generation level for each 10-minute period, *t*. Then the selected 10-minute generation levels are averaged by hour to achieve the necessary scale for use as an hourly load modifier in the Demand module. The last row in Table 4 is highlighted to show that in that 10-minute period the DNE limit ceases to constrain wind plant production, resulting in total generation below the DNE limit.

$$DNE_{i,t} = \{\sum(N_{t-1} + N_{t-2} + \cdots + N_{t-6}) \div 6\} \times 1.08$$

$$L_{i,t} = MIN\left(DNE_{i,t}, N_{i,t}\right)$$

$$DNE_{i,h} = \sum(L_{i,t}\ \forall\ t \in h) \div 6$$

Where:

$DNE_{i,t}$ = generation under Do Not Exceed limit at wind plant *i* in period *t* (MW)

$N_{i,t}$ = generation at wind plant *i* in period *t* (MW)

$L_{i,t}$ = effective generation at wind plant *i* in period *t* (MW)

$DNE_{i,h}$ = generation under Do Not Exceed limit at wind plant *i* in hour *h* (MW)

The wind data and hourly load data used is from the year 2005. Since there is 2004 wind data available a DNE dispatch limit can be calculated for the first hour of the year, whereas if only one year of data were available that would be impossible.

It is assumed that wind plants maximize their electricity generation by always producing at the DNE limit or, if wind conditions make reaching the DNE limit physically impossible, the maximum possible level below that point. The wind plants are assumed to not be curtailing their own generation. This assumption seems reasonable considering that MISO reported DIRs generated electricity at their Forecast Maximum Limit 95.2% of the time during the first six months of the program, when the limit would have been binding (Midwest ISO 2011).

3.3 Load Demand

ORCED utilizes hourly system load data from various utilities and control areas to create the demand profiles for each study region. The National Electric Reliability Council region for New England corresponds directly to the control area of ISO New England, so system load data can be taken from ISO New England's publicly available data. This is not true of most areas of the country, and in those cases the regional load is the weighted average of the component system loads. Once an hourly system load profile is input into the Demand module, ORCED steps the hourly loads up to the study year based on projections from the NEMS database. A detailed description of the method by which ORCED steps-up the hourly load profile is presented in the Demand section of Chapter 4.

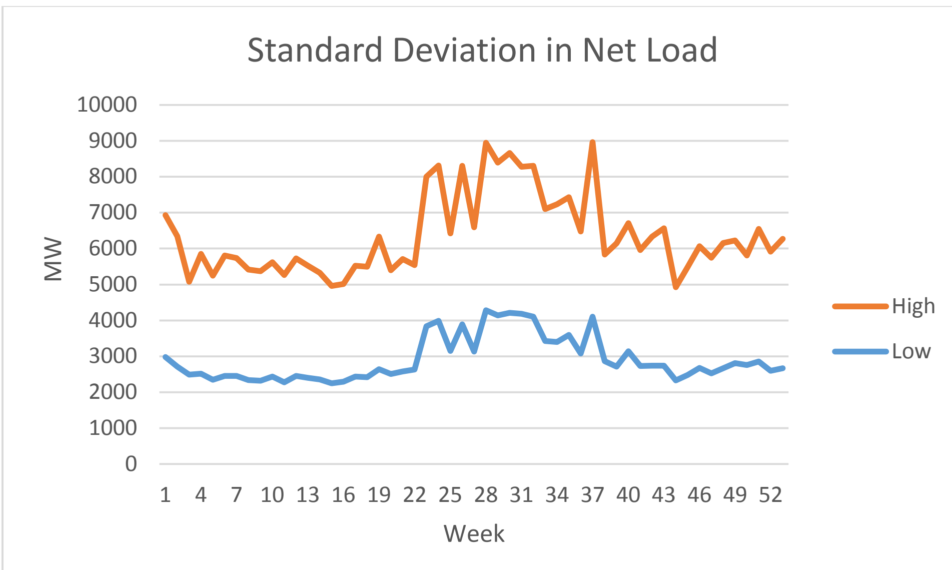


Figure 7. Weekly net load standard deviations in no-DNE High and Low scenarios

Net load is what demand remains to be served by conventional generators after electricity production from wind is subtracted out. Over the course of the study year, the average net load decreases when moving from the Low scenario to the High scenario, with larger reductions occurring in the winter and offpeak seasons. Most importantly from a system reliability and forecasting standpoint, as Figure 7 illustrates, variability in net load increases significantly as wind capacity is added to the grid.

Although the model comes equipped with demand profiles for each region using 2010 data, a 2005 system load profile taken from ISO New England is used in this study in order to remain consistent with the available wind data. ORCED can only accurately simulate year-to-year operations of regional electricity markets, so looking at the entire period from 2004-2006 is unfeasible.

Wind speeds, and the associated electricity generation by wind plants, can be correlated to some extent with load demand. Therefore, using hourly load and wind generation data from the same year is essential in avoiding any potential bias in the results (Orwig, et al. 2012). Upon analyzing the available wind data from January 1, 2004 to January 1, 2007, it appeared that 2006 exhibited below-average wind speeds for the region. Although the sample size was small, 2004 and 2005 were similar and assumed to be representative of the typical yearly wind resources available to New England. The other consideration in choosing a representative year to study is the presence of any abnormal seasonal load events. While 2005 witnessed no major events, during January 14-16, 2004 New England experienced “unusually extreme weather and electricity demand conditions (ISO New England 2004).”

3.3.1 Demand Response

Like wind, the contribution of demand response to meeting system load enters the model by adjusting downward hourly load demand. The demand response programs that ISO-NE administers have evolved to include two main categories: (1) a program that reduces load to support system reliability and includes the Real-Time Demand Response and Real-Time Emergency Generation resources; and (2) a program that reduces load through energy-efficiency and other non-dispatchable measures which includes On-Peak and Seasonal-Peak resources. There is a third program in which consumers can reduce their demand according to electricity prices in the real-time and day-ahead markets, but it makes up a very small portion of total demand response and is currently in a transitional phase (ISO New England 2012b).

In response to concerns that energy and reserve markets alone would not provide sufficient price signals to ensure that forecasted generation capacity needs would be met, ISO New England implemented a capacity market. Annual capacity obligations are acquired through the Forward Capacity Auction (FCA), which is binding for the period three years in the future. In the most recently completed FCA 6, which applies to resources committed in 2015/2016, a total of 4257 MW of demand response resources were committed.

Table 5. Demand response resources cleared in Forward Capacity Auction 6

Summer Peak		
	Active	1999 MW
	Passive*	2673 MW
Winter Peak		
	Active	1837 MW
	Passive*	2471 MW

* Includes incremental energy efficiency forcasted beyond 2016

(Source: ISO New England, CELT Report, 2012)

Demand response resources must clear the FCA and subject themselves to audits from ISO New England to prove that the capacity they claim in the auction is actually available. Real-Time Demand Response and Real-Time Emergency Generation assets are classified as ‘active’ resources, meaning that the system operator can dispatch them according to the needs of the system. On-Peak and Seasonal-Peak assets are classified as ‘passive’ resources, in that they are not dispatchable.

ISO New England does not forecast future demand response beyond what clears in the FCAs, but incremental gains through energy efficiency do appear in current forecasts for passive demand response. The total contribution of passive demand response will most likely be higher than the amounts forecasted today, but this number serves as an acceptable estimate because energy efficiency resources comprise the largest share of passive demand response assets that clear in the FCA.

Active demand response gets used sparingly, perhaps once or twice a year for only a few hours when the system is experiencing highly unusual conditions that leave it short of available generating capacity. Since active demand response resources do not impact serviceable load on a daily basis, it is not essential to model them precisely. For a study such as this, the most important aspect of demand response to capture is the contribution by passive demand response resources.

Aided by the fact that Seasonal-Peak makes up a comparatively small percentage of total passive demand response, both Seasonal-Peak and On-Peak resources are grouped together to modify demand according to the On-Peak dispatch methodology. On-Peak demand resources are triggered automatically, every day during peak seasonal hours. ISO New England defines peak seasonal hours in the winter as 6pm to 8pm, and summer hours as 1pm to 5pm (ISO/RTO Council 2013). Applicable winter months, including winter shoulder months, are December, January, February, and March. The summer months, including shoulders, are April, May, June, July, August, September, October, and November. Passive demand response MWs from Table 5 are subtracted from hourly load demand in both cases with and without DNE dispatch limits.

CHAPTER 4

OAK RIDGE COMPETITIVE ELECTRICITY DISPATCH MODEL

4.1 History and Organization

The Oak Ridge Competitive Electricity Dispatch (ORCED) model can simulate the operations and costs of wholesale electric power markets for any year up to 2035. Using a historical hourly load profile for one region of the U.S., ORCED projects hourly load in a future year using energy consumption forecasts from FERC. Public data available through the Energy Information Administration's (EIA) National Energy Modeling System (NEMS) is used to calculate operational costs for generating units in the study region. ORCED then dispatches generating units to meet projected demand after accounting for limited electricity imports and exports. The model assumes no transmission constraints (Hadley 2008).

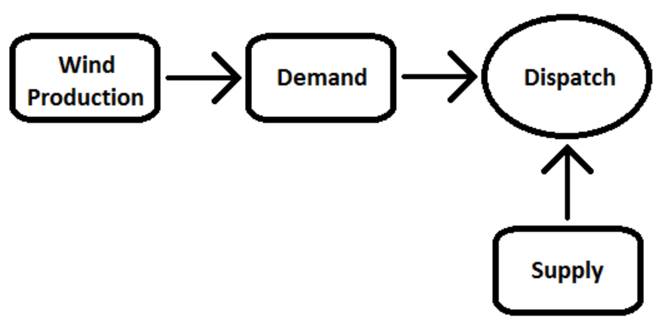


Figure 8. ORCED Model flow diagram

Originally developed in the mid-1990s as the Oak Ridge Financial Model to investigate the effects of wholesale electricity market deregulation on a single utility, ORCED has evolved into a tool used to assess the effect of technological change on a single region (Hadley 2008). Adaptability is one of the model's strengths, as it can be easily modified to suit the needs of a particular study. In 2012, ORCED was used in a national plug-in hybrid electric vehicles study (Hadley and Tsvetkova 2012), and a DOE-funded study on demand response potential in the Eastern Interconnection (Baek, et al. 2012).

ORCED is comprised of four spreadsheet-based modules that are linked with various macros. The Demand module starts with an hourly load profile, adjusts that profile to capture contributions from demand modifiers like wind plants and demand response, then converts the modified hourly load profile into seasonal Load Duration Curves (LDCs). The Supply module sorts all generating units by region, calculates the variable cost of electricity for each, and aggregates the generating units into 200 bins to mimic power plants. In the Dispatch module the composite power plants are dispatched to meet annual demand represented by the LDCs.

This is the first research effort using ORCED to focus on wind energy integration issues, and certain modifications to the model were required to better represent how wind plants satisfy load. In order to remain consistent with the approach taken in other wind integration studies, electricity generation from wind plants enters the model as an hourly load modifier. Hourly production for each wind plant in the study is first calculated outside of ORCED, then introduced to the Demand module where it is subtracted from hourly load demand. The hourly demand remaining after subtracting contributions from wind plant generation and passive demand response is defined as net load, and represents the load demand to be served by conventional dispatchable generators. Wind plants submit supply bids into wholesale electricity markets that are near zero or even negative after accounting for subsidies. The net load concept reflects the fact that energy from wind plants will always clear in the market before generators with fuel costs barring transmission constraints, which this study assumes are nonexistent.

4.2 Supplies

In the Supply module generators in the study region are aggregated into power plant groups based on operational characteristics. ORCED bins all of the power plants in a region by plant and fuel type in order to limit the amount of generating units it has to use in the dispatch routine. Power plant groups function as pseudo-power plants within the model to reduce the computational burden. The power plant groups are sorted in increasing order by their variable cost of producing electricity, creating a merit order of generation assets, and then exported into the Dispatch module.

Due to the energy-limited nature of hydro and pumped storage plants, water is not always available in reservoirs or rivers to drive turbines, they are modeled separately within the Dispatch module. Wind plants, although treated as dispatchable generators in previous studies using ORCED, enter into the Demand module as a load modifier.

ORCED starts by calculating the variable cost for each power plant using energy input, generation, and emissions data, then converts the figure to \$/kWh.

$$VC_i = F_i + OM_i + S_i + N_i + C_i$$

Where:

VC_i = variable cost for generator *i* (\$/MWh)

F_i = fuel expense for generator *i* (\$/MWh)

OM_i = variable operations & maintenance for generator *i* (\$/MWh)

S_i = SO_2 allowance cost for generator *i* ($/MWh)

N_i = NOx allowance cost for generator *i* ($/MWh)

C_i = CO_2 allowance cost for generator *i* ($/MWh)

Once variable cost is determined the plants are sorted by fuel type (ex. bituminous and subbituminous coal), plant type (ex. combined cycle, steam turbine, coal, etc.), and variable cost. With the plants categorized and ranked, ORCED can go about assigning them to one of the 200 groups that will act as power plants to be used in the Dispatch routine (Hadley 2008).

$$B_r = round\{\sum_{x \in S_r} C(x) \div Z_r\}$$

Where:

B_r = number of plant groups created for unique combination *r* of plant type *i* and fuel type *j*

$\sum C(x)$ = total capacity of power plants *x* (MW)

S_r = set of power plants *x* for unique combination *r* of plant type *i* and fuel type *j*

Z_r = user determined average plant group size for unique combination *r* of plant type *i* and fuel type *j* (MW)

The order in which power plant groups are sorted reflects their role in the system as peaking or baseload generation. Oil plants and non-combined cycle gas plants provide much of the peaking power for the system. Combined cycle plants are highly efficient and are supplanting coal as baseload. The renewable plant group contains biomass and municipal solid waste plants that are typically baseload. ‘Must-run’ plants are non-dispatchable cogeneration facilities, those that provide electricity and heat, and the four New England nuclear plants.

ORCED calculates variable and fixed operating characteristics for each of the 200 plant groups as a weighted average of the component generators’ characteristics. Variable characteristics include emission rates, plant efficiency (heat rate), and variable operation and maintenance costs. Fixed characteristics include fuel costs, fixed operation and maintenance costs, and plant age. (Hadley 2008).

4.3 Demands

After inputting hourly load data from a past year, ORCED escalates that historical load profile to the future year being studied using forecasts of net energy for load from ISO New England. Net energy for load is defined as all electricity generated within a particular region, plus imports to that region, and transmission losses, less exports to other regions.

$$A_t = D_t \times (Y \div SN)$$

$$NL_t = D_t - P_t - W_t - E_t$$

Where:

A_t = adjusted (stepped-up) demand in hour *t* (MW)

D_t = reference hour demand from historical profile in hour *t* (MW)

Y = total load demand in reference year – 2005 (GW)

SN = forecasted net energy for load in study year - 2020 (GW)

NL_t = net load in hour *t* (MW)

P_t = passive demand response in hour *t* (MW)

W_t = electric generation from wind plants in hour *t* (MW)

E_t = exports of electricity in hour *t* (MW)

Any adjustments to inter-regional electricity trade can be made in the Demand module. In New England, imports and exports occur over interfaces with New Brunswick, Quebec, and New York. This study assumes the same levels of imports and exports as the ORNL study on demand response potential in the Eastern Interconnection (Baek, et al. 2012).

Electricity generation from wind plants enters the Demand module like passive demand response. After the historical hourly profile has been escalated to the future year, in this study 2020, hourly contributions to servicing load from wind plants and passive demand response resources are subtracted to arrive at the hourly net load to be served by dispatchable power plants in the supply stack.

4.3.1 Conversion to Load Duration Curves

Generators have capacity ratings that change over the course of a year, so ORCED analyzes demand by breaking the year into three seasons; summer, winter, and offpeak. Seasonal lengths can be customized within the model to fit the study region because loads are not uniform across the U.S. (Hadley 2008). ISO New England breaks the year into four categories: (1) winter performance months (December-January); (2) winter shoulder months (February-March); (3) summer performance months (June-August); and (4) summer shoulder months (September-November and April-May) (ISO New England 2013). Since ORCED cannot accommodate four distinct seasons, and because the historical load profiles of certain months in the ISO-defined shoulder months did not fit being included together in the offpeak season, some of the months in ISO New England's shoulder months were included in the summer and winter seasons. In this study summer is defined as June-September, winter as December-February, and the offpeak season as October-November and March-May. The ISO-defined seasons are used to determine seasonal demand response contributions in ORCED.

An LDC represents the percent of time in a season that load demand is at a certain power level. ORCED calculates the load demand range in each season to create 200 bins that all other hourly observations in that season get assigned to (Hadley 2008). Observations in each bin are summed together, translated into a cumulative curve of hours at the respective load demand levels defined by the bin limits, and then converted into the LDC. For example, in the summer season containing 2,928 hours the first bin will contain only the observations in that bin, the second bin will contain all observations from the first and second bins, and so forth until the 200th bin contains all 2,928 hours. To derive the LDC, each bin is divided by the total number of hours in that particular season to obtain the percentage of time demand equals or exceeds a given power level. (Hadley 2008). To reduce computation time requirements, the 200-point LDCs are converted to twelve-point LDCs before they are exported into the Dispatch module. A macro in Excel fits the twelve points to the original LDC so that variance is minimized while keeping total demand constant (Hadley and Tsvetkova 2012).

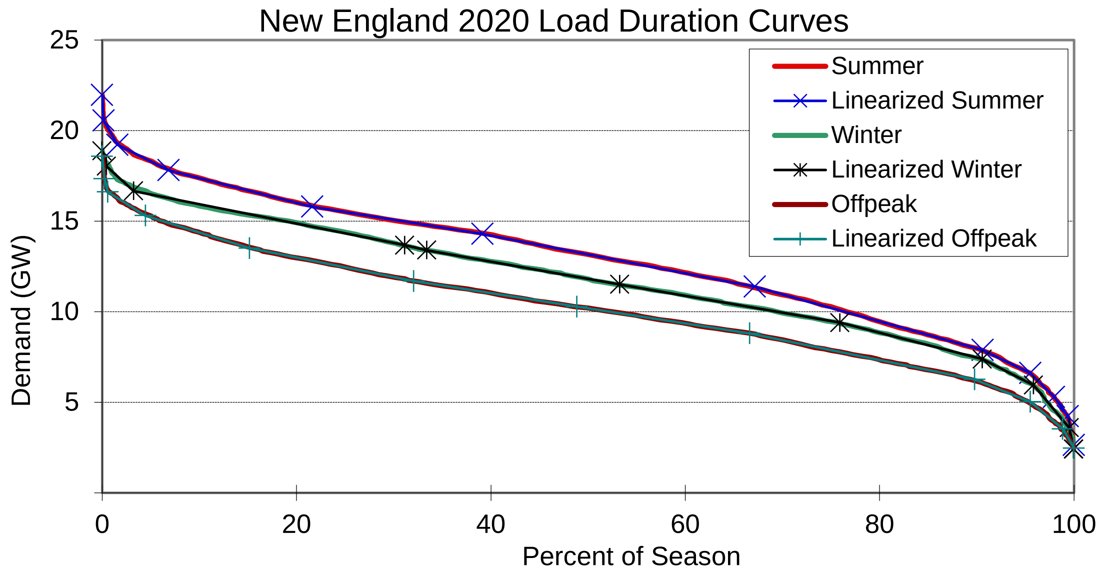


Figure 9. Load duration curves under High installed wind capacity

LDCs are indicative of the electric power system being studied. A system with many peaking plants will have steep curves, while flat curves indicate a system where plants are used evenly. This is especially noticeable on the segment of the LDC between 0% and 10% of the season. Notice that the summer LDC is above the winter LDC in Figure 9. This reflects the fact that New England is a summer-peaking system, meaning the annual peak is during the summer when cooling loads are at their highest.

4.4 Dispatch

The dispatch of power plants to meet annual load can be simulated once electric generation from hydro and pumped storage plants is accounted for and system operating reserve requirements are specified. In the dispatch procedure the power plant required to meet the last MW of demand in each segment of the LDC is assigned according to the merit ordering of plants by variable cost. The variable cost of the marginal power plant determines the wholesale market price of electricity in that segment of the LDC for all plants. After assigning marginal generators to each segment of the LDC, ORCED calculates the energy market revenues and environmental costs for each power plant.

4.4.1 Hydro and Pumped Storage

Unlike thermal generating units that always have the ability to purchase fuel, most hydro plants are constrained by available water supplies. These hydro plants can be described as energy limited. There is a strong seasonal component involved, as annual weather and precipitation cycles affect production. In areas with significant snowpack, like New England, the late-winter and spring months witness a jump in hydro output (EIA 2012c).

Since water comes at no cost to hydro plants, their variable cost of producing electricity is extremely low. System operators dispatch hydro units during periods in which demand is high to minimize generation from expensive peaking plants. ORCED reduces demand by total hydro capacity until all the electric generating potential from hydro plants is exhausted. In Figure 10, the space between the original LDC and the hydro-adjusted LDCs reflects the total available hydro generation.

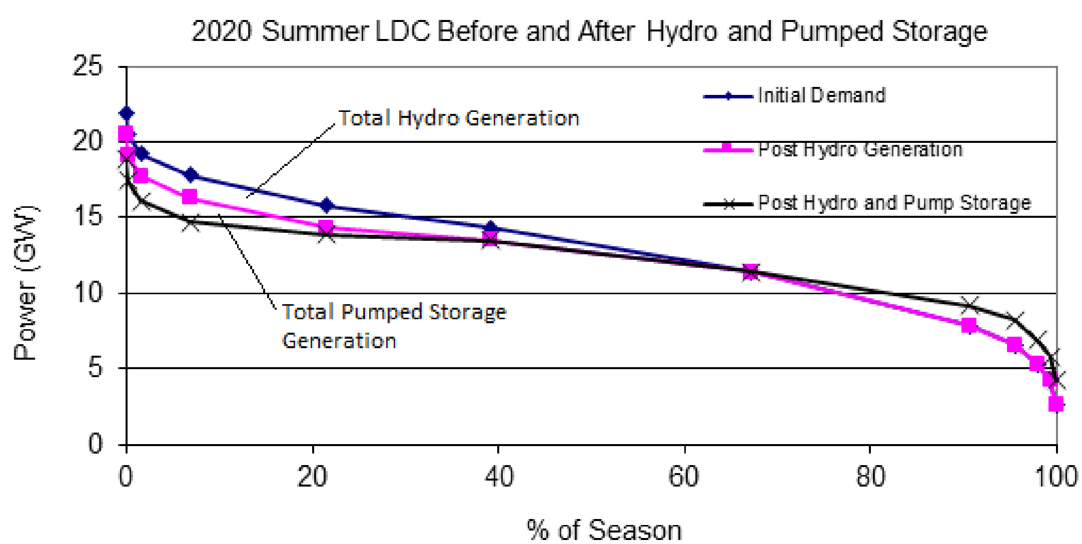


Figure 10. Load duration curve after hydro adjustment

Through the first 4-5% of the season, up to the fourth point on the LDC, hydro units are able to reduce demand by their full capacity. After that point the generators become limited by available water for generation and cease producing electricity at full capacity. ORCED drops each point of the initial LDC down by the total hydro capacity then recalculates the amount of available energy remaining from hydro generation. The process is repeated for subsequent points until no hydro energy remains.

Of course, hydro generators will not exclusively be dispatched during those times in which demand is highest. Run-of-river facilities, as opposed to hydro units that use reservoirs, still have incentive to operate at other times during the season. One of the aggregated power plants from the Supply module can be used to capture a portion of hydro capacity to be dispatched regularly. Hydro power plants dispatched in this way would in effect shift the LDC downward by the capacity of the plants, as the low variable cost of hydroelectricity lends itself to baseload operation.

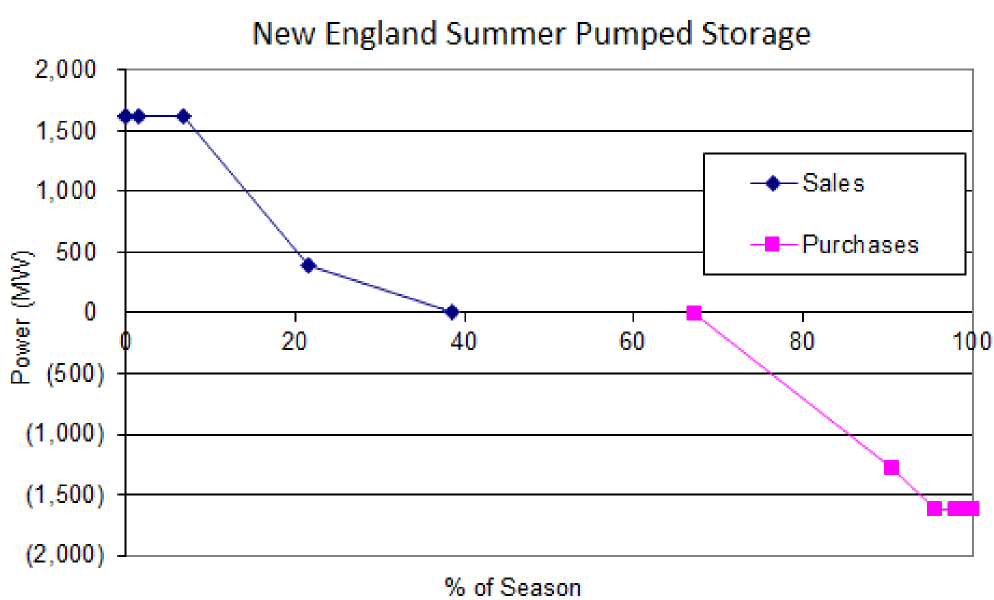


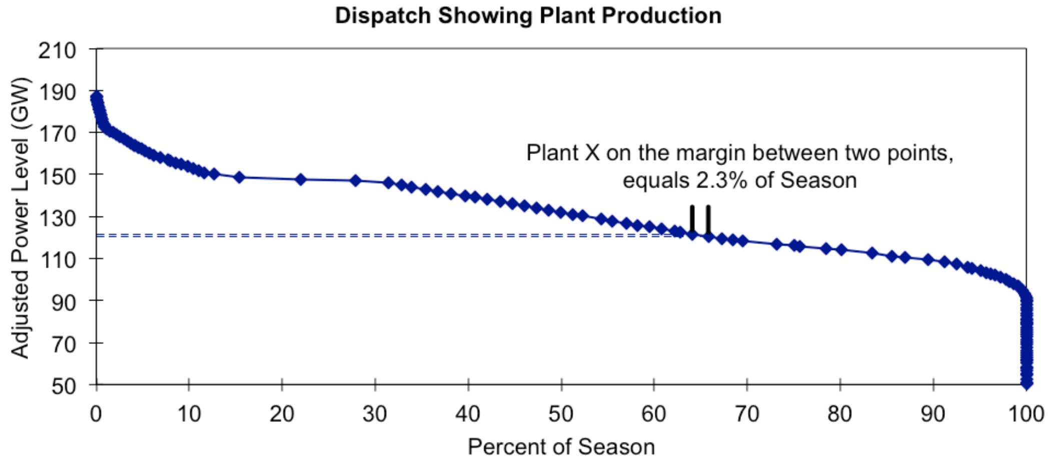
Figure 11. Pumped storage sales and purchases

In addition to reducing demand during those periods of the year when demand is the highest, pumped storage hydro plants also increase demand when loads are at their lowest (Hadley and Baek 2012). Pumped storage plants purchase electricity from the grid when wholesale prices are low in order to pump water into elevated reservoirs. When prices rise during times of peak demand water is released down from the reservoirs to power turbines, allowing the plant to realize a profit from the price differential. Pumped storage plants help balance the system by utilizing cheap electricity from efficient baseload plants that generate energy even when demand is low. Figure 11 shows the electricity generated and purchased by hydroelectric and pumped storage plants during the summer season.

The pumped storage plants in New England were built during the 1970s primarily to take advantage of the abundant cheap electricity from regional nuclear plants constructed during the same period. New England has over 1600 MW of pumped storage on the system, all but 7 MW of which comes from two plants. The 1000 MW Northfield Mountain pumped storage plant on the Connecticut River was the largest facility of its kind in the world when it entered service in 1972 (GDF Suez 2013).

4.4.2 Dispatch Routine

ORCED calculates the percent of time in each season that demand exceeds 213 power levels. These power levels are determined by the cumulative capacities of the 200 power plant groups in the merit order (201 points total) and the twelve points from the LDC. Between each of these power levels and the associated percent of season that demand exceeds those levels, a plant group is determined to be on the margin and setting price for all plant groups behind it in the merit order.



(Source: Oak Ridge National Lab, ORCED Documentation, 2012)

Figure 12. Dispatch curve showing marginal time segments

The method by which ORCED dispatches power plant groups hinges on the way forced outage rates are treated in the model. Forced outages are instances when a power plant goes out of service due to unplanned circumstances, such as mechanical failures or sudden fuel unavailability. ORCED can represent the impact of forced outage rates on generation probabilistically or by derating the power plant group's capacity. If a plant group is derated, its maximum capacity is reduced by the forced outage rate. Power plant groups treated probabilistically are dispatched at their full summer and winter seasonal capacities, but the impact of forced outages on these plants manifests itself by increasing the amount of time more expensive plant groups are forced to run.

Instead of assuming that all plant groups are always available at a reduced capacity, treating plant groups probabilistically reflects more accurately what occurs during forced outage events. Probabilistic dispatch simulates circumstances in which a large power plant unexpectedly goes offline, forcing more expensive peaking plants to quickly make up the difference in generation. ORCED selects large baseload plant groups towards the bottom of the merit order for probabilistic dispatch so the effects of forced outages are more pronounced. Up to 25 power plant groups can be treated probabilistically, but 10-12 is ideal because calculations become exponentially more computationally demanding as additional plant groups are included.

$$T_i(p) = (1 - FOR_i) \times T_{i-1}(p) + FOR_i \times T_{i-1}(p - C_i)$$

$$T_{i-1}(p) = (1 - FOR_{i-1}) \times T_{i-2}(p) + FOR_{i-1} \times T_{i-2}(p - C_{i-1})$$

$$\cdots$$

$$T_0 = LDC(p)$$

Where:

$T_i(p)$ = time (percent of season) that demand plus outages would exceed power level *p* with *i* number of plant groups treated probabilistically

i = the number of plant groups being treated probabilistically up to power level *p*

p = power level (MW)

FOR_i = forced outage rate for probabilistic plant *i*

C_i = capacity of probabilistic plant group *i* (MW)

$LDC(p)$ = a linear interpolation of the percentage of season that the load duration curve equals power level *p*

If 12 power plant groups are dispatched probabilistically, as is the case in this study, and the remaining plant groups are derated, then *i* will equal 12 beginning at the power level associated with the probabilistically dispatched plant group highest in the merit order. For each subsequent power level, i will equal 12. As $i \rightarrow \infty$ for a constant power level p, $T_i(p) \rightarrow \infty$.

During the summer and winter peaks capacity is only impacted by the forced outage factor. In the offpeak season capacity is impacted exclusively by planned outages. The planned outage factor captures the propensity of power plants to perform maintenance and refueling operations during the offpeak season when demand is low. When calculating the derating amount for the offpeak season, differences in summer and winter lengths and capacities must be accounted for because planned outage factors are based on annual generation.

$$G_{Total} = G_{Summer} + G_{Winter} + G_{Offpeak}$$

$$G_{Total} = C_S \times (1 - FOR_S - POR) \times \gamma_S + C_W \times (1 - FOR_W - POR) \times (\gamma_W + \gamma_O)$$

Where:

G = generation (MW)

C = capacity (MW)

FOR = forced outage rate

POR = planned outage rate

γ = seasonal percentage of year

Define seasonal generation to internalize planned outage rate within season in order to isolate the planned outage effect on offpeak capacity:

$$G_S = C_S \times (1 - FOR_S)$$

$$G_W = C_W \times (1 - FOR_W)$$

$$G_O = C_O \times (1 - FOR_W)$$

Rearranging the first equation and substituting:

$$C_O = \{[C_W \times (1 - FOR_W) \times \gamma_O - POR \times (\gamma_O + \gamma_W)] - C_S \times POR \times \gamma_S\}$$
$$\div [(1 - FOR_W) \div \gamma_O]$$

Note that winter capacity and offpeak capacity are equal. Typically the winter capacity rating for a power plant will apply for the offpeak season as well. Because planned outage factors do not have an effect in the summer or winter seasons, they have no impact on the probabilistic dispatch of plant groups.

4.4.3 Operating Reserves

Wholesale electricity markets require reserves on the system to meet rapid changes in load. In New England there are several different products sold in the ancillary services market that provide assurances on the availability of reserves over different time frames. ORCED simulates reserve revenues to power plant groups in a simplified manner. The user specifies an amount of reserves required at any individual segment of the dispatch curve as a percentage of demand. In this study the reserve requirement is set at 7%.

$$R_{i,t} = (MC_i - P_t) \times L_i \div A_i$$

Where:

$R_{i,t}$ = marginal cost of supplying reserves for power plant *i* over segment *t* ($)

t = dispatch curve segment (% of season)

i = power plant in dispatch merit order not at full generation

MC_i = marginal cost of power plant group *i* ($)

P_t = energy market price over segment *t* ($)

L_i = minimum generation level of power plant group *i* (MW)

A_i = capacity available to supply reserves of power plant group *i* (MW)

A power plant group required for reserves will receive revenues equal to the marginal cost of supplying those reserves. The marginal cost of a plant group supplying reserves will always be greater than the energy market price, or else the plant group would be generating electricity already.

In each segment of the dispatch curve, ORCED calculates the marginal cost of supplying reserves for each power plant group not being fully dispatched to meet load. The last plant group needed to meet the reserve requirement will set the reserve market price for all plant groups supplying reserve capacity. In order to accommodate minimum generation requirements of certain power plants, there can be instances when a power plant group is dispatched to meet load demand has a portion of its capacity held back for reserves. This is referred to as 'posturing'.

For example, assume that the final 50 MW of system reserves are needed from Plant B that has a minimum generation requirement of 100 MW. Plant A, a 200 MW plant with a minimum generation requirement of 100 MW which cleared the energy market and is generating electricity at full capacity, would be postured. Plant A would reduce generation by 50 MW to supply reserves, still above its minimum generation requirement, and Plant B would be able to start-up and generate at its minimum generation level. Plant B would receive reserve market revenues on 50 MW of generation, and energy market revenues on the other 50 MW. Plant A would not be penalized for providing system reserves, and would still receive the higher energy market price on all of its generation.

4.4.4 Pricing and Revenues

The last power plant in the merit order required to meet load demand in each segment of the dispatch curve is described as being 'on the margin'. This marginal generator sets the energy market price for that segment of the dispatch curve, and all plants operating beneath the marginal generator will realize a profit because the energy market price is greater than their variable costs. For a single segment of the dispatch curve in one season, energy market revenues are calculated by multiplying power plant group generation by the length of the segment and by the number of hours in that season. This is repeated for every segment in all three seasons to determine annual revenues from the energy market

$$G_{i,S} = \sum_{t \in S} (C_{i,t} \times H_S \times L_t)$$

$$R_{i,S} = \sum_{t \in S} (C_{i,t} \times H_S \times L_t \times P_t)$$

$$R_{i,Total} = R_{i,summer} + R_{i,winter} + R_{i,offpeak}$$

Where:

$G_{i,S}$ = generation of power plant *i* in season *S* (MWh)

$C_{i,t}$ = dispatched capacity of power plant *i* in segment *t* (MW)

H_S = hours in season S

L_t = length of dispatch segment t (% season)

$R_{i,S}$ = energy market revenue for power plant i in season S ($)

P_t = energy market price in dispatch curve segment t ($/MWh)

The marginal power plant group that sets price in each segment of the dispatch curve does not generate energy uniformly throughout the segment like the plant group beneath it in the merit order. To obtain a value of C for the marginal power plant, ORCED takes the average of the dispatched capacity across segment t of the dispatch curve. If the dispatch curve segment represents the fraction from 45% to 50% of the season, and the power levels at those fractions of the season were 600 MW and 500 MW respectively, then the marginal plant's dispatched capacity in that segment would equal 550 MW.

Energy market revenues realized by wind plants cannot be determined within ORCED because wind generation is pulled out of supply before the dispatch routine. For the six model runs, two dispatch regimes for each of the three installed wind capacity levels, data on hourly loads from the Demand module and seasonal price data by power level from the Dispatch module are used to calculate revenues to wind generators. The net load for each hour is matched to the corresponding energy price at that power level for the appropriate season the hour falls in. Wind plants have a variable cost of zero, and act as price takers in the market. Taking the extra step to calculate wind revenues outside of ORCED is beneficial in general, as it allows the user to observe the prevailing market price at every hour of the year which would be otherwise impossible.

With hourly energy market prices in hand, the price and total wind generation for each hour are simply multiplied to arrive at hourly energy market revenue. If necessary, this step can be taken for any of the individual wind plants, though this study focuses only on the entire cohort of wind plants in New England. Total wind plant revenue is the sum of energy market revenues and subsidies for generation from renewable energy, which come in the form of Renewable Energy Credits (RECs) and the federal renewable energy production tax credit. RECs are market-based, representing the environmental benefit of producing a MW of energy from renewable sources. This study assumes a REC price of $40/MWh. The production tax credit, pegged at 2.3 $₵/kWh$ for wind plants, is available for the first 10 years of operation. Because the amount of installed wind capacity that would not qualify for the production tax credit in 2020 is very small, that capacity built before 2010, it is assumed that every MW of electricity generated by wind plants receives the subsidy.

$$WR_h = (P_h + REC + PTC) \times G_h$$

Where:

WR_h = aggregate wind revenue in hour h ($)

P_h = energy market price in hour h ($/MW)

REC = renewable energy credit price ($/MWh)

PTC = production tax credit benefit ($/MWh)

G_h = aggregate wind energy generation in hour h (MW)

4.4.5 Environmental Costs

ORCED calculates environmental costs in terms of carbon dioxide (CO_2), sulfur dioxide (SO_2), and nitrogen oxide (NO_X) emissions. Power plant emissions are a function of generation amounts, fuel inputs, plant efficiency, and emission mitigation factors – such as NO_X catalytic reduction equipment and flu scrubbers. Energy from coal, natural gas, biomass, uranium, residual oil, and other sources of fuel for power plants emit different levels of pollutants. To calculate primary energy usage for each plant, measured in millions of British thermal units (mmBtu), total annual generation is multiplied by a measure of power plant efficiency, the heat rate (Btu/kWh).

CO_2 emissions depend solely on the carbon content of the various fossil fuels. The fuel source CO_2 emission rate, measured in kilograms of carbon per mmBtu (kg C/mmBtu), is multiplied by a power plant's primary energy usage to determine annual plant CO_2 output. Unlike CO_2, SO_2 and NO_X emission levels are determined by plant specific factors that can reduce the amount of pollutant emitted. The EPA regulates power plant emissions of SO_2 and NO_X, so there is detailed data on the types of combustion controls and mitigating technologies employed at each power plant in New England. SO_2 is produced almost exclusively by coal plants, but NO_X is emitted by all fuel sources during combustion.

ORCED allows the user to specify the price per ton of emitting the three pollutants. However, since this study focuses only on how implementing DNE dispatch limits impacts the level of annual emissions realized in the various scenarios, default emission input prices from NEMS are used to calculate power plant variable cost.

CHAPTER 5

RESULTS

5.1 Overview

This study sought to first calculate the change in wind plant generation that will be realized when moving from a system in which wind plants self-schedule their generation to a system in which dispatch is characterized by DNE limits. Total wind generation was found to decline by 6.47% in the study year after DNE limits were imposed. The second objective was to quantify the effects that change in wind generation will have on market outcomes: generation from non-wind power plants, energy market prices, power plant revenue, and emission levels. Results showed that the small reduction in wind generation due to DNE limits had muted effects on corresponding market outcomes.

Three levels of installed wind capacity are modeled in the study. The level of installed wind capacity in the Low scenario is equal to the sum of wind plant capacity from currently operational wind plants and proposed wind plants in the ISO New England interconnection queue as of January 1st, 2013. Installed wind capacity increases from scenario to scenario linearly. That is, the installed wind capacity in the Low level is increased by 100% to arrive at the level of installed wind capacity in the Medium scenario, and 200% to arrive at the level of installed wind capacity in the High scenario. Defining installed wind capacity in this way allows the identification of any non-linear effects of dispatch regime change on the market outcomes outlined in the second objective.

A total of six simulations form the basis of this study; DNE dispatch and no-DNE self-scheduled dispatch regimes run for each of the three installed wind capacity scenarios. ORCED was used to run the six simulations of power plant dispatch for New England wholesale electricity markets for the study year 2020 and generate results on market outcomes. Results tables for the six simulations can be found in the Appendix.

5.2 Wind Plant Generation

Under DNE limit dispatch, wind plant production is constrained frequently by small amounts. DNE limits are found to be binding in 28.47% of the season, but often by less than 2% of plant nameplate capacity. Figure 13 shows the cumulative frequency of DNE constrained events, which are measured by the amount of wind energy avoided as a percentage of nameplate capacity in order to standardize measurements across different sized plants.

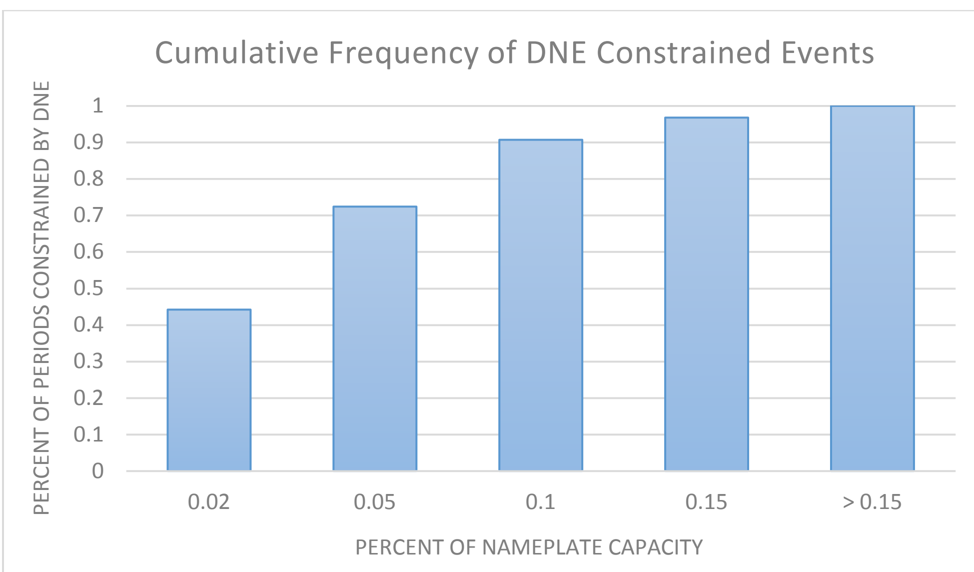


Figure 13. Wind energy avoided as percent of plant nameplate capacity in periods where DNE limit is binding

In a large number of constrained events the wind energy avoided is at levels less than 2% of plant nameplate capacity, and in over 90% of constrained events the wind energy avoided is under 10% of plant nameplate capacity. Only in 3.3% of DNE constrained events do curtailments exceed 15% of plant nameplate capacity.

Because the modeled wind levels are linear increases of the installed capacity in the Low scenario, the change in wind generation realized by moving from no-DNE self-scheduled wind dispatch to DNE limit dispatch remains the same in all three installed wind scenarios. For the Low, Medium, and High wind scenarios, Table 5 shows the effect of implementing DNE limit dispatch on wind generation.

Table 5. Change in aggregate wind plant generation under DNE limit dispatch

	Low	*Medium*	*High*
Annual			
Total decrease, GW	698.77	1,397.54	2,096.31
Monthly average, MWh	79.77	159.54	239.30
% change under DNE	-6.47%		
Summer			
Total decrease, GW	251.89	503.78	755.67
Monthly average, MWh	68.60	137.20	205.79
% change under DNE	-7.20%		
Winter			
Total decrease, GW	186.88	373.75	560.63
Monthly average, MWh	86.52	173.03	259.55
% change under DNE	-5.95%		
Offpeak			
Total decrease, GW	260.00	520.01	780.01
Monthly average, MWh	88.80	177.60	266.40
% change under DNE	-6.26%		
Summer Peak			
Total decrease, GW	40.98	81.95	122.93
Monthly average, MWh	66.95	133.91	200.86
% change under DNE	-7.21%		
Winter Peak			
Total decrease, GW	43.42	86.84	130.27
Monthly average, MWh	102.41	204.82	307.23
% change under DNE	-6.59%		

Percentage changes for annual results are from the weighted averages of the three seasons weighted by the length of the season and seasonal wind plant generation. The comparatively high generation from wind plants in the winter and offpeak seasons, although both seasons are shorter than the summer season, will contribute more to the annual average because of higher absolute amounts of generation. Further, the changes in wind generation listed for peak hours should be only be compared to the average of the respective season in order to understand how generation is affected in peak hour periods relative to the rest of season.

Wind plant generation decreased by 6.47% over the course of the study year after DNE limit dispatch implementation. A slightly higher percentage of summer wind generation is avoided compared to the yearly average, while the percentage of winter wind generation lost to DNE limits is a little less than the yearly average. DNE limits have a greater limiting effect on wind generation at times when wind speeds are ramping up. Wind speeds, and as an extension wind generation, are characterized by more pronounced up-ramping events in the summer, while average wind speeds are more consistent in the winter.

During the winter season, wind generation avoided under DNE limit dispatch occurs disproportionately in the peak load hours when wholesale energy prices are the highest. This is because the peak load hours in the winter coincide with the time that wind speeds ramp up the most. In the summer peak hours, the change in wind generation after DNE limit dispatch implementation is essentially the same as that observed for the summer average. This result is expected given that more wind generation is avoided under DNE limit dispatch in periods when wind generation is increasing.

5.3 Non-Wind Plant Generation

For each power plant group the total annual electricity generation was calculated, as well as the percent of the year that the power plant acted as the wholesale energy price setter by being the last plant dispatched. When a power plant in the merit-order sets the wholesale energy price by meeting the last MW of demand in a time period, it is referred to as being 'on the margin' or the marginal generator. The wholesale market price is directly impacted by the amount of time in a given year certain power plant types are on the margin. If power plants with higher variable electricity production costs are on the margin more frequently, such as unscrubbed coal plants or oil plants, wholesale prices will be higher on average. In this section both of these metrics are evaluated for all power plants other than wind plants, and in the following section wholesale electricity prices are evaluated.

Several power plants generate the same amount of electricity across all of the model runs. That is, no change in dispatch regime or increase in wind capacity impacts their operation. Generation from wind capacity additions will displace inefficient and polluting fossil fuel plants before any other generator. Nuclear power plants have such low variable costs, \$10/MWh to \$12/MWh, that they are nearly guaranteed to run at full capacity most of the year. Once a nuclear power plant starts up it only shuts down to refuel, which occurs once every 18-24 months. Similarly, hydroelectric and pumped storage plants do not realize changes in generation at increasing installed wind capacity levels due to their low fuel costs. ORCED dispatches hydroelectric and pumped storage plants under the assumption that they will generate electricity during those periods in which demand, and wholesale energy prices, is highest. Other power plants in the study are classified as “must-run” plants. Must-run plants are always on, often because they function as combined heat and power plants.

Results show that oil fueled steam turbine power plants produce at full generation in all model runs as well. Given the nature of oil as a peaking fuel this may seem surprising at first glance, but there is a logical explanation. Not only is a large portion of oil steam turbine power plant capacity represented by a single must-run plant, but oil steam turbine power plants are typically called upon during the summer peak hours when wind generation is virtually non-existent. During these peak summer hours, inefficient coal and gas-fired combustion turbine power plants, having higher variable costs, are displaced by increases in wind generation before oil fired steam turbine plants.

Interestingly, in the High installed wind capacity scenario, nuclear power plants begin setting the energy market price for a portion of the year. During the hours in which nuclear power plants are generating on the margin, wind plant electricity generation is high enough to drive all fossil fueled plants, even combined cycle gas plants, out of the market. These periods occur during the winter, most likely overnight, when load demand is low and wind speeds are peaking.

At each level of installed wind capacity, the decrease in wind generation caused by DNE dispatch implementation is offset by generation increases from coal, natural gas, municipal solid waste, and biomass plants. However, the share of electricity generation provided by these four types of plants to offset the loss in wind generation is not consistent across installed wind capacity levels. Capacity factors, which represent power plant generation relative to maximum capability, indicate how frequently power plants are called upon by the grid operator. If a certain power plant type exhibits non-constant changes in capacity factors from one installed wind capacity level to the next, it points to a disproportionate change in generation.

Due to generation from wind plants in the Medium scenario, coal plants not equipped with flu scrubbers realize a 66% reduction in generation over the Low wind capacity scenario, with a corresponding capacity factor decline. Moving from the Medium to High installed wind capacity level, these “dirty” coal plants realize a further 50% reduction in generation to 16% of their generation in the Low installed wind scenario. Coal plants fitted with flu scrubbing equipment, or “clean” coal plants, experience linear reductions in generation as wind capacity increases, indicated by the constant 7% decrease in capacity factor observed in successive installed wind capacity scenarios.

New England relies heavily on natural gas, which as a fuel source supplies 50% of electricity in the region under current conditions. Increased wind generation displaces more MW of natural gas than any other fuel source, but natural gas actually sets the market price more often at higher wind capacity levels. For power plants, trends in generation do not have to coincide with trends in the time spent on the margin. The capacity of natural gas plants in New England is so high that even when wind is displacing a portion of natural gas in a given hour, there is almost too much for wind generation to offset. Only in the High wind scenario do there start to be hours in which enough wind generation is coming on the system to supplant all natural gas, indicated by nuclear plants occupying time as the price setting marginal plants. In reality, nuclear plants cannot easily reduce their electricity generation to follow load as the marginal generator, so generation from wind plants would be curtailed before nuclear plants were called upon to reduce electricity production.

In the Low scenario, under self-scheduled wind dispatch, combined cycle gas plants generate 46.71% of the energy for the region, and set prices as the marginal generator almost 75% of the year. As installed wind capacity levels increase from the Low scenario to the Medium scenario, natural gas fueled plants set prices in 76.55% and 83.67% of the season respectively – a 7.1% rise. This despite a decline in generation by 9,000 GW. Scrubbed coal plants almost double the time they spend on the margin – from 4.92% to 9.14%.

Natural gas and scrubbed coal plants have the lowest variable cost of all these groups, so they get dispatched first. Biomass and municipal solid waste plants have slightly higher variable generation costs, and unscrubbed coal plants offer into the market higher still because of SO_2 emission costs. During the winter, when peak loads are lower than the summer, wind plant generation is high enough throughout the season to ensure that only natural gas and scrubbed coal power plants are on the margin. Natural gas and scrubbed coal plants therefore realize lower levels of generation like all other non-wind plants, but they set prices more frequently.

Moving from the Medium to High installed wind capacity scenario something slightly different happens. There is again an increase in the time natural gas plants spend on the margin, rising to 87.77% of the year, but scrubbed coal plants spend nearly a third less time as marginal generator, falling to 6.78% of the year. In this case, wind generation forces scrubbed coal off the margin in the winter, like it did to unscrubbed coal and biomass previously, leaving the stack of combined cycle plants to occupy the margin almost exclusively.

There is an exception to this in short periods when wind generation at its strongest. Occasionally, there is so much cheap electricity coming onto the grid that all the generation from combined cycle natural gas plants is rendered unnecessary, resulting in nuclear power plants setting the wholesale energy price. As mentioned in the beginning of this section, nuclear power for the first time operates on the margin, 1.29% of the year, during those periods in which wind generation is high enough to reduce net load levels below nuclear capacity.

Across installed wind capacity scenarios, changes in generation and marginal supply for the two dispatch regimes are comparable. The one significant exception occurs in the Medium installed wind capacity scenario. Moving from self-scheduled wind plant dispatch to DNE limit dispatch in the Medium scenario, the time scrubbed coal plants spend on the margin falls by 2.25%. This is a large difference compared to the change within the Low scenario (-0.6%) and the High scenario (0.5%). The deviation is an interesting result that can be explained by two competing forces. First, the small increase in time that unscrubbed coal plants spend on the margin in the DNE dispatch limit case may offset the decrease realized by scrubbed coal somewhat. Under DNE dispatch limits wind generation is reduced from self-scheduled levels. Logically, when generation from wind plants decreases net load increases, and more capacity must be dispatched from more expensive generators to meet load. Unscrubbed coal has slightly higher variable costs than scrubbed coal, so when scrubbed coal is on the margin and wind generation falls, unscrubbed coal is the first to come online.

The less intuitive reason for the sharp decline is the reduction in wind generation variability that DNE dispatch ushers in. Natural gas plants spend an additional 1.5% of the year on the margin under DNE limit dispatch in the Medium scenario, which at first glance goes against the dispatch logic just described between scrubbed and unscrubbed coal plants. Although natural gas plants have lower variable costs than coal, they manage to capture time on the margin from coal during periods when net load is increasing. Since the DNE limits are based on moving averages, the level of wind generation is reduced but variability is reduced and the wind production curve becomes smooth. It is likely that during the winter and offpeak seasons, the slight change in wind production brought about by implementing DNE dispatch limits is at just the right level to consistently deny scrubbed coal plants hours on the margin.

5.4 Wholesale Energy Price

In Table 6, the second row contains the percent price change observed when moving to DNE limit dispatch holding installed wind capacity level constant, and the third row indicates the percent price change from the previous installed wind capacity level holding dispatch regime constant.

As expected, moving to a dispatch regime using DNE limits results in price increases on average. When there is less generation from wind plants resulting from DNE limits, more generation from power plants with non-zero variable energy costs are required to meet the increase in net load. The effect on annual average price increases becomes more pronounced at successively higher levels of installed wind capacity, as the amount of MW lost to DNE limits rises in absolute terms.

Table 6. Simulated energy market prices

	Price ($/MWh)					
	Low	*Low DNE*	*Med*	*Med DNE*	*High*	*High DNE*
Avg hourly price	43.03	43.15	41.54	41.74	39.85	40.23
% change under DNE		0.29%		0.49%		0.96%
% change on wind level			-3.46%	-3.28%	-3.92%	-3.49%
Avg summer price	42.46	42.44	41.43	41.45	40.01	40.34
% change under DNE		-0.03%		0.05%		0.82%
% change on wind level			-2.41%	-2.34%	-3.36%	-2.63%
Avg winter price	42.88	42.94	41.11	41.57	39.26	39.70
% change under DNE		0.14%		1.12%		1.13%
% change on wind level			-4.13%	-3.19%	-4.33%	-4.36%
Avg offpeak price	43.85	44.20	41.99	42.23	40.10	40.50
% change under DNE		0.80%		0.58%		1.01%
% change on wind level			-4.26%	-4.47%	-4.31%	-3.91%
Avg peak summer price	44.99	44.95	43.72	43.84	42.57	42.82
% change under DNE		-0.06%		0.25%		0.56%
% change on wind level			-2.80%	-2.49%	-2.56%	-2.27%
Avg peak winter price	46.18	46.45	43.88	44.11	42.02	42.42
% change under DNE		0.53%		0.72%		0.85%
% change on wind level			-4.98%	-5.03%	-4.02%	-3.65%

During the summer season, the average and peak wholesale energy prices increase somewhat after implementing DNE limits. However, the increases are economically insignificant and likely caused by the peculiarities of the ORCED dispatch routine related to probabilistic plants and hydroelectric calculations. Because wind plants generate such a low amount of electricity in the summer, implementing DNE limit dispatch has almost no effect on summer prices until installed wind capacity levels are at their highest.

Looking at the percent change in peak and average summer prices across installed wind capacity scenarios holding dispatch constant, when moving to the Medium scenario from the Low scenario the effect on prices during peak hour is greater than in all hours. In moving from the medium to high installed wind capacity scenario that trend is reversed. Installed wind capacity increases meaningfully impact peak wholesale prices, in both the summer and the winter, before average wholesale prices due to the steepness of the supply curve is at higher power levels. Only small amounts of generation can have the effect of forcing a generator off the margin that is twice as high as the next most expensive power plant.

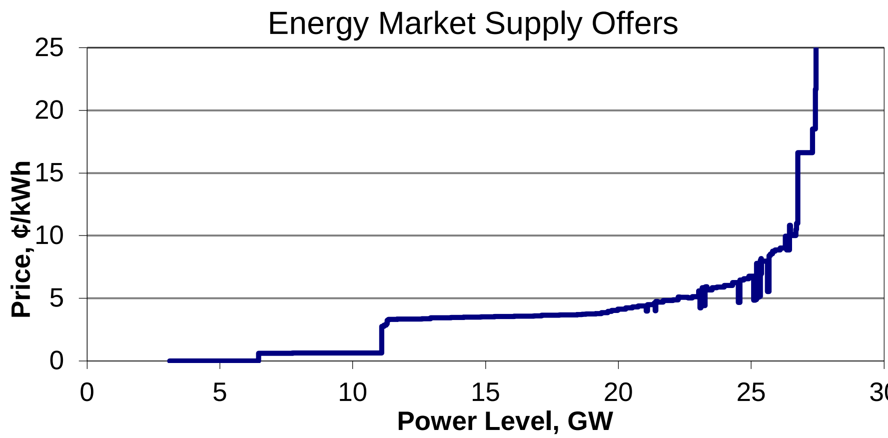


Figure 14. New England marginal supply curve – Medium-DNE scenario 2020

Average wholesale energy prices are impacted more in the winter and offpeak seasons when generation from wind plants is at a maximum. The average annual, summer, and winter wholesale energy prices decrease at an increasing rate at higher levels of wind capacity, holding the dispatch regime constant. This same phenomenon does not occur in the offpeak season, nor is it observed during the peak hours in any season. As discussed previously, wholesale energy prices are at their most sensitive to changes in generation during the peaks hours when expensive plants are on the margin. During offpeak hours, it takes more wind generation to impact the already low wholesale energy prices. The price-setting marginal power plant would be on the flat part of the marginal supply curve, and so price is less sensitive to changes in generation.

Wholesale energy prices increase after the implementation of DNE limit dispatch, and they do so to a greater degree at successive levels of installed wind capacity. The offpeak season is the only part of the year that does not follow this trend. Within the

Medium scenario during the offpeak season, the power plants forced off the margin by wind generation under no DNE limits likely have similar variable costs to those plants that take their place on the margin when DNE limits are implemented. For instance, in the offpeak season wind generation could be pushing more expensive coal plants off the margin to the benefit of combined cycle gas plants at the Low scenario, while in the Medium scenario, wind generation could be forcing combined cycle plants off the margin to the benefit of slightly cheaper combined cycle plants.

5.5 Wind Plant Revenue

Wind plants receive revenue from sales of electricity in the energy market and through subsidies tied to their generation. REC prices in New England are currently trading at their cap of $65/MWh. This study assumes a lower REC price of $40/MWh for 2020, since it is unlikely that prices will remain at the maximum level as more qualified renewable energy projects come online and begin selling RECs. After accounting for the production tax credit, wind plants receive a total subsidy of $63/MWh of generation.

With subsidy per MW of electricity roughly 50% higher than the wholesale energy market price, wind plants realize far higher revenues outside the energy market. Subsidizing generation in this way alters the production decision of wind plants, effectively incentivizing them to produce electricity even when wholesale energy prices are negative. This is not a problem in New England at the levels of installed wind capacity examined in the study, but negative prices would probably be seen at capacity levels slightly above the High scenario.

Trends observed in wind plant revenues from the energy market follow from patterns in wind generation and wholesale energy price previously discussed. Whereas wholesale prices respond to DNE dispatch implementation by decreasing more at successive wind levels, revenues increase at a slower rate compared to the preceding installed wind capacity level. As average wholesale prices rise disproportionately, revenues fall by similar proportions.

On average, wind plants earn 12.5% of their summer season revenue during peak hours, and only 6.8% of their winter hours during peaks. In the summer it's most likely a case of small amounts of wind generation profiting from very high energy prices. In the winter, wind plants earn the most money when the volume of their generation is highest throughout the night and morning hours, despite low energy prices in those periods.

5.6 Emissions

Emissions are measured in thousands of tons, or kTons. For every 3.2 GW of wind capacity added to the grid, emissions of CO_2, SO_2, and NO_X are reduced by about 5,000 kTons, 6.6 kTons, and 1.5 kTons respectively. All changes in emissions are driven by shifts in generation by coal, gas, and to a lesser extent, biomass fueled power plants. Holding dispatch regime constant, CO_2 reductions pick up pace slightly when moving from the Medium to High scenario, while SO_2 and NO_X emission reductions slow down. This discrepancy is driven by unscrubbed coal plants and combustion turbine oil plants seeing the sharpest decline in generation occur when the installed wind capacity is increased to the Medium scenario from the Low scenario. Overall, installing more wind capacity will have a greater downward effect on the percentage of CO_2 emitted, 17% average, relative to SO_2 and NO_X, 10% average.

Changing wind dispatch regimes from self-scheduled generation to DNE limit dispatch reduces wind generation, which increases output and pollution from fossil fuel generators. Moving to DNE limit dispatch has small effects on SO_2 and NO_X emissions, increasing them by 2.1% and 1.7% respectively at the highest wind capacity level. The increase in NO_X emissions caused by switching to DNE dispatch rises more when moving from the Medium to High installed capacity scenario. This can be explained by a proportionately greater decrease in combined cycle gas plant generation. The opposite holds true for SO_2, with a larger drop in emissions occurring when installed wind capacity levels increase from the Low to Medium scenario. Again, the quick decline in production from coal plants that occurs at the Medium installed wind capacity level is the driving influence.

CHAPTER 6

DISCUSSION, EXTENSIONS, AND CONCLUSION

6.1 Discussion

Electricity generation by wind plants is going to expand rapidly as a share of total electricity generation in the next decade. To manage the influx of generation from wind plants in New England, these plants will be dispatched according to DNE limits beginning in 2015. This study adds to the understanding of how implementing DNE limit dispatch will impact wind plants specifically and the wholesale energy market in general.

Findings show that DNE limit dispatch will reduce wind generation by 6.47% compared to the current self-scheduled wind plant dispatch regime. That reduction in production from wind equals 700 MW, 1400 MW, and 2100 MW in the Low, Medium, and High wind scenarios respectively. Although the share of summer wind generation avoided was higher than the average for the year, and the percentage of winter wind generation avoided was lower than the average for the year, in absolute terms more generation was lost in the winter and offpeak seasons.

In the winter a proportionately greater share of wind generation is lost during peak demand hours than in the season at-large. This phenomenon is likely driven by exaggerated periods of upward wind speed ramping during winter peak demand hours. It also indicates that wholesale prices in the winter will increase proportionately more during peak hours than the non-peak hours.

The key assumption made here is that of no wind curtailment caused by transmission constraints or wind forecast uncertainty in either dispatch regime. Making this assumption overestimates the reduction in wind generation post-DNE limit dispatch if wind plants are not generating energy under the no-DNE self-scheduled dispatch regime at the maximum level that the physical availability of wind will permit. It is possible that under DNE limit dispatch certain wind plants might in fact produce more electricity depending on how severe they are being curtailed and how effective DNE limits are at alleviating issues leading to said curtailment.

It is possible that those DNE-constrained events that are very small as a percentage of plant nameplate capacity, which comprise the majority of occurrences, are just the kind of curtailment events that will be mitigated by having DNE dispatch limits in place. For policy governing the dispatch of wind plants, the implication is that DNE limits will negatively impact wind generators ability to produce electricity by a very small amount at worst.

This study also sought to quantify the effects that a change in dispatch regime would have on non-wind power plant generation, wholesale energy prices, and emissions. To calculate these market outcomes, the New England wholesale electricity market was modeled as a single priced market using the ORCED model. Wind plant generation estimates for the year 2020 under both dispatch regimes were fed into ORCED, and the competitive dispatch of power plants to meet annual load demand was simulated for the six scenarios. Effects on power plant generation, wholesale energy prices, and emissions levels after implementation were found to be unsubstantial.

Adding more installed wind capacity to the system shifts the supply curve to the right, but the extent of the supply curve shift depends on the amount of wind available in each hour of the year. Even at low installed wind capacity levels, implementing DNE dispatch will have a pronounced effect on marginal generators and wholesale energy prices during high demand hours, as peaking plants are required in far fewer periods. Data on wholesale energy prices post-DNE implementation supports this. After DNE limit dispatch is implemented in the Low scenario and generation from wind plants falls, wholesale prices increase more during the winter peak hours than they do on average. In the Medium and High scenarios, post-DNE dispatch implementation there is not a similar increase in wholesale energy prices during peak hours. Baseload generation begins to be impacted at higher installed wind capacity levels as wind generation reaches a critical mass that enables it to force combined cycle gas plants off the margin as price setting units.

Wholesale prices during the summer are unaffected by implementing DNE limit dispatch at the Low and Medium wind scenarios. At the highest level of installed wind capacity small effects are seen on summer prices - reflecting the fact that wind generation will contribute little to reducing summer net demand and, as an extension, wholesale prices in the summer, until wind energy has a significant presence in the region.

Estimating levels of wind generation in 2020 under no-DNE self-scheduled wind dispatch and DNE limit dispatch has shown that a substantial amount of wind generation is avoided when implementing DNE limits. However, the caveat is that these findings rest upon the unrealistic assumption that no wind is curtailed under the self-scheduled dispatch regime, and thus are likely an overestimate of the actual reductions that can be expected. Results indicate that the effects of DNE dispatch implementation on wholesale energy prices and emissions are small relative to the associated reductions in wind generation. Interestingly, because of the shape of the supply curve, and the hourly and seasonal deviations in average wind speeds, the effects on these market outcomes are inconsistent for linear increases in installed wind capacity. Extensions to this study are discussed in the next section, and the chapter concludes with a comment on the successes and limitations of this research.

6.2 Extensions

More research is needed to understand the effect that integrating wind energy, as well as other renewable resources, will have on wholesale electricity markets. The methods developed through this research were conceived as a precursor to more in-depth studies regionally. Assuming no wind plant curtailment under a self-scheduled dispatch regime is tenuous at best. Relaxing that assumption and investigating the impacts of curtailment in particular areas of the grid is the logical next step of future research.

Wind plants, in New England and beyond, are often connected to parts of the grid far from concentrations of customers where the transmission infrastructure was not designed to accommodate large generation assets. These weaker parts of the grid are joined to the rest of the system over low voltage transmission lines, typically 115 kilovolts, which have a propensity to get overloaded under high wind generation. Whether it be motivated by the existence of government subsidies or simply a lack of due diligence in the planning process, potential losses from curtailment have been overlooked by wind plant owners. Whatever the cause, state renewable portfolio standard targets guarantee that thousands of MW of wind capacity will be added to the grid in coming years. That generation needs to be integrated intelligently to fully capture the beneficial effects wind power has on wholesale price and emissions reductions.

The next phase of research will focus on two issues: first, how effective DNE limit dispatch is at reducing wind curtailments, and second, identifying areas in which upgrades to the transmission system would be most economically efficient. At this time there are no data on wind plant curtailments in New England, but that is poised to change by year end. Once the centralized wind forecasting system being implemented by ISO New England is fully operational, scheduled for the second half of 2013, data on curtailments will start to be collected for the first time.

This study focused on what implementing DNE dispatch would do to wind generation in a controlled environment where self-scheduled wind plants are *unconstrained*. It is the counterfactual to the future study in which curtailment data are made available. By the second half of 2014, with one year of curtailment data collected, the model used in this study could be updated to show the effect of DNE limit dispatch implementation on *constrained* wind generation. The results would likely be different, given that the reduction in curtailments attributed to implementing DNE limit dispatch may offset the 6.47% decline in wind generation found here.

Understanding how effective DNE limit dispatch is at reducing curtailments is essential to quantifying the economic benefit of transmission system expansions. Transmission projects are expensive and have long lead times to completion. Even if the money was available to build the necessary high-voltage lines to connect all future wind projects, they would not get done quickly. Stakeholders faced with limited funds, including ratepayers, need to decide what lines to upgrade first. Introducing curtailment assumptions to the model provides the accurate context to identify marginal benefits from upgrading parts of the transmission system.

A touted benefit of DNE limit dispatch is that wind plants will be more apt to participate in the day-ahead energy market in New England. The day-ahead market acts as hedge against volatility in the real-time market and acts as the starting point for next-day generation commitment. Wind resources have historically avoided participating because it was difficult to predict what their next day generation would be, leaving them vulnerable to wind volatility if they made commitments in the day-ahead market. With the centralized forecasting system and DNE dispatch, wind plants will have access to the information on future generation that will enable them to participate. Although it is beyond the capabilities of ORCED, it would be useful to estimate the potential benefit to wind plants realized by committing generation in the day-ahead market. The financial benefit associated with participation in the day-ahead market is an additional component to consider when calculating the total effect on wind plant revenue.

6.3 Conclusion

This study was conducted to quantify the amount of wind plant generation that would be lost after the planned implementation of DNE dispatch limits in New England, and to calculate the effects of that decrease on power plant generation, wholesale energy prices, power plant revenue, and emissions levels. Evaluating the transition to DNE limit dispatch was conducted at three levels of installed wind capacity. This was done in order to determine if the changes brought on by DNE limit implementation to power plant generation, wholesale energy prices, power plant revenue, and emissions levels respond non-linearly to increased wind generation.

As one of the few studies on DNE limit dispatch, the findings from this research offer a valuable point of comparison for subsequent inquiries. The methods and model design employed here will be applicable to future studies when data on curtailments becomes available.

Results show that imposing DNE dispatch limits reduce total wind generation by a small amount – 6.47% over the course of the study year. Considering that the study assumes no wind curtailment due to transmission constraints or wind forecast uncertainty, 6.47% is the maximum reduction that would be witnessed under otherwise ideal market conditions for wind generators. The study finds that DNE dispatch limits constrain wind generation often – 28.4% of the year on average – but that the levels of wind generation avoided were typically small – 72.4% of DNE limit curtailment events were below 5% of plant nameplate capacity.

DNE limit dispatch is a necessary step forward in integrating intermittent renewable resources into the New England electricity markets. The potential disadvantage to wind plants in terms of lost revenue during DNE-constrained periods is shown to be small even under the most conservative estimate. Further research efforts should consider the effectiveness of DNE limit dispatch on reducing curtailments to develop a more accurate picture of what wind plants in New England, and the grid at large, stand to gain from the new dispatch regime.

APPENDIX

SUMMARY DATA TABLES

A1. WIND PLANT GENERATION

	Aggregate Wind Plant Generation					
	Low	*Low DNE*	*Med*	*Med DNE*	*High*	*High DNE*
Annual gen, GW	10,796.62	10,097.85	21,593.25	20,195.71	32,389.87	30,293.56
Avg annual, MWh	1,232.49	1,152.72	2,464.98	2,305.45	3,697.47	3,458.17
% change under DNE	-6.47%					
Summer gen, GW	3,496.52	3,244.63	6,993.05	6,489.26	10,489.57	9,733.90
Avg summer, MWh	952.21	883.61	1,904.42	1,767.23	2,856.64	2,650.84
% change under DNE	-7.20%					
Winter gen, GW	3,143.38	2,956.51	6,286.77	5,913.01	9,430.15	8,869.52
Avg winter, MWh	1,455.27	1,368.75	2,910.54	2,737.51	4,365.81	4,106.26
% change under DNE	-5.95%					
Offpeak gen, GW	4,156.72	3,896.71	8,313.43	7,793.43	12,470.15	11,690.14
Avg offpeak, MWh	1,419.64	1,330.85	2,839.29	2,661.69	4,258.93	3,992.54
% change under DNE	-6.26%					
Summer peak gen, GW	568.50	527.53	1,137.00	1,055.05	1,705.51	1,582.58
Avg peak hour, MWh	928.92	861.97	1,857.85	1,723.94	2,786.77	2,585.91
% change under DNE	-7.21%					
Winter peak gen, GW	659.17	615.75	1,318.34	1,231.50	1,977.51	1,847.25
Avg peak hour, MWh	1,554.65	1,452.24	3,109.30	2,904.47	4,663.94	4,356.71
% change under DNE	-6.59%					

A2. POWER PLANT GENERATION AND MARGINAL PRODUCTION

Low wind - noDNE

	Generation		Capacity	Time on
Plant Type	TWh	% Total	Factor	Margin
Coal Unscrubbed	1.17	0.90%	18%	12.99%
Coal Scrubbed	6.70	5.13%	65%	4.92%
Oil ST	4.89	3.75%	18%	0.01%
Oil CT	0.00	0.00%	0%	0.00%
Gas ST	0.79	0.60%	9%	0.08%
Gas CC	61.00	46.71%	62%	74.68%
Gas CT	0.33	0.25%	3%	1.79%
Nuclear	36.57	28.00%	90%	0.00%
Muni. Solid Waste	0.70	0.54%	15%	2.46%
Biomass	1.71	1.31%	33%	3.06%
Wind Onshore	9.21	7.06%	38%	0.00%
Wind Offshore	1.60	1.22%	39%	0.00%
Hydro	5.94	4.55%	46%	0.00%
Pumped Storage	0.00	0.00%	0%	0.00%
Total	130.59		49%	

Low wind - DNE

	Generation		Capacity	Time on
Plant Type	TWh	% Total	Factor	Margin
Coal Unscrubbed	1.21	0.93%	19%	14.07%
Coal Scrubbed	6.76	5.17%	66%	4.34%
Oil ST	4.89	3.75%	18%	0.01%
Oil CT	0.00	0.00%	0%	0.00%
Gas ST	0.79	0.61%	9%	0.09%
Gas CC	61.55	47.13%	62%	73.93%
Gas CT	0.35	0.27%	4%	1.63%
Nuclear	36.57	28.00%	90%	0.00%
Muni. Solid Waste	0.71	0.54%	15%	2.43%
Biomass	1.72	1.32%	34%	3.49%
Wind Onshore	8.61	6.59%	35%	0.00%
Wind Offshore	1.49	1.14%	37%	0.00%
Hydro	5.94	4.55%	46%	0.00%
Pumped Storage	0.00	0.00%	0%	0.00%
Total	130.59		49%	

Medium wind - noDNE

	Generation		Capacity	Time on
Plant Type	TWh	% Total	Factor	Margin
Coal Unscrubbed	0.36	0.28%	6%	3.94%
Coal Scrubbed	5.99	4.59%	58%	9.14%
Oil ST	4.89	3.74%	18%	0.00%
Oil CT	0.00	0.00%	0%	0.00%
Gas ST	0.78	0.60%	9%	0.03%
Gas CC	52.36	40.09%	53%	82.60%
Gas CT	0.18	0.14%	2%	1.04%
Nuclear	36.57	28.00%	90%	0.00%
Muni. Solid Waste	0.48	0.37%	10%	1.43%
Biomass	1.45	1.11%	28%	1.83%
Wind Onshore	18.41	14.10%	38%	0.00%
Wind Offshore	3.19	2.44%	39%	0.00%
Hydro	5.94	4.55%	46%	0.00%
Pumped Storage	0.00	0.00%	0%	0.00%
Total	130.59		44%	

Medium wind - DNE

	Generation		Capacity	Time on
Plant Type	TWh	% Total	Factor	Margin
Coal Unscrubbed	0.41	0.32%	6%	4.30%
Coal Scrubbed	6.09	4.66%	59%	6.87%
Oil ST	4.89	3.74%	18%	0.01%
Oil CT	0.00	0.00%	0%	0.00%
Gas ST	0.78	0.60%	9%	0.05%
Gas CC	53.55	41.01%	54%	83.90%
Gas CT	0.20	0.15%	2%	1.26%
Nuclear	36.57	28.00%	90%	0.00%
Muni. Solid Waste	0.50	0.38%	10%	1.73%
Biomass	1.47	1.12%	29%	1.89%
Wind Onshore	17.22	13.18%	35%	0.00%
Wind Offshore	2.98	2.28%	37%	0.00%
Hydro	5.94	4.55%	46%	0.00%
Pumped Storage	0.00	0.00%	0%	0.00%
Total	130.59		45%	

High wind - noDNE

	Generation		Capacity	Time on
Plant Type	TWh	% Total	Factor	Margin
Coal Unscrubbed	0.17	0.13%	3%	1.86%
Coal Scrubbed	5.26	4.03%	51%	6.78%
Oil ST	4.89	3.74%	18%	0.00%
Oil CT	0.00	0.00%	0%	0.00%
Gas ST	0.78	0.60%	9%	0.01%
Gas CC	42.81	32.78%	43%	87.77%
Gas CT	0.15	0.11%	2%	0.36%
Nuclear	36.48	27.94%	90%	1.29%
Muni. Solid Waste	0.41	0.32%	9%	0.64%
Biomass	1.32	1.01%	26%	1.29%
Wind Onshore	27.61	21.14%	38%	0.00%
Wind Offshore	4.78	3.66%	39%	0.00%
Hydro	5.94	4.55%	46%	0.00%
Pumped Storage	0.00	0.00%	0%	0.00%
Total	130.59		40%	

High wind - DNE

	Generation		Capacity	Time on
Plant Type	TWh	% Total	Factor	Margin
Coal Unscrubbed	0.20	0.15%	3%	2.29%
Coal Scrubbed	5.38	4.12%	52%	7.27%
Oil ST	4.89	3.74%	18%	0.00%
Oil CT	0.00	0.00%	0%	0.00%
Gas ST	0.78	0.60%	9%	0.02%
Gas CC	44.66	34.20%	45%	87.24%
Gas CT	0.15	0.12%	2%	0.43%
Nuclear	36.52	27.96%	90%	0.84%
Muni. Solid Waste	0.42	0.32%	9%	0.69%
Biomass	1.35	1.03%	26%	1.23%
Wind Onshore	25.82	19.77%	35%	0.00%
Wind Offshore	4.47	3.42%	37%	0.00%
Hydro	5.94	4.55%	46%	0.00%
Pumped Storage	0.00	0.00%	0%	0.00%
Total	130.59		41%	

A3. WHOLESALE ENERGY PRICE

	Price ($/MWh)					
	Low	*Low DNE*	*Med*	*Med DNE*	*High*	*High DNE*
Avg hourly price	43.03	43.15	41.54	41.74	39.85	40.23
% change under DNE		0.29%		0.49%		0.96%
% change on wind level			-3.46%	-3.28%	-3.92%	-3.49%
Avg summer price	42.46	42.44	41.43	41.45	40.01	40.34
% change under DNE		-0.03%		0.05%		0.82%
% change on wind level			-2.41%	-2.34%	-3.36%	-2.63%
Avg winter price	42.88	42.94	41.11	41.57	39.26	39.70
% change under DNE		0.14%		1.12%		1.13%
% change on wind level			-4.13%	-3.19%	-4.33%	-4.36%
Avg offpeak price	43.85	44.20	41.99	42.23	40.10	40.50
% change under DNE		0.80%		0.58%		1.01%
% change on wind level			-4.26%	-4.47%	-4.31%	-3.91%
Avg peak summer price	44.99	44.95	43.72	43.84	42.57	42.82
% change under DNE		-0.06%		0.25%		0.56%
% change on wind level			-2.80%	-2.49%	-2.56%	-2.27%
Avg peak winter price	46.18	46.45	43.88	44.11	42.02	42.42
% change under DNE		0.53%		0.72%		0.85%
% change on wind level			-4.98%	-5.03%	-4.02%	-3.65%

A4. ENERGY MARKET REVENUE – WIND PLANTS

	Aggregate Energy Market Revenue to Wind Plants (M$)					
	Low	*Low DNE*	*Med*	*Med DNE*	*High*	*High DNE*
Annual revenue	454.06	425.72	861.08	808.91	1,213.42	1,148.57
Average monthly	37.84	35.48	71.76	67.41	101.12	95.71
% change under DNE		-6.24%		-6.06%		-5.34%
% change on wind level			89.64%	90.01%	77.60%	79.79%
Summer revenue	145.48	134.81	280.93	260.68	400.19	374.67
Average monthly	29.10	26.96	56.19	52.14	80.04	74.93
% change under DNE		-7.33%		-7.21%		-6.38%
% change on wind level			93.11%	93.36%	81.98%	84.55%
Winter revenue	133.51	125.82	250.54	237.85	349.47	333.64
Average monthly	44.50	41.94	83.51	79.28	116.49	111.21
% change under DNE		-5.75%		-5.06%		-4.53%
% change on wind level			87.67%	89.04%	74.10%	76.12%
Offpeak revenue	178.80	168.60	336.70	317.06	471.93	447.99
Average monthly	44.70	42.15	84.17	79.27	117.98	112.00
% change under DNE		-5.71%		-5.83%		-5.07%
% change on wind level			88.30%	88.06%	75.64%	77.66%
Peak summer revenue	18.20	16.83	35.01	32.54	50.59	47.14
Average monthly	3.64	3.37	7.00	6.51	10.12	9.43
% change under DNE		-7.56%		-7.06%		-6.81%
% change on wind level			92.36%	93.40%	85.57%	86.77%
Peak winter revenue	9.17	8.69	17.06	16.17	24.21	22.88
Average monthly	3.06	2.90	5.69	5.39	8.07	7.63
% change under DNE		-5.22%		-5.18%		-5.49%
% change on wind level			86.06%	86.13%	77.98%	77.15%

A5. SUBSIDY REVENUE TO WIND PLANTS FROM RECs AND PTC (M$)

Base	Base DNE	Med	Med DNE	High	High DNE
680.19	636.16	1,360.37	1,272.33	2,040.56	1,908.49

A6. ENERGY MARKET REVENUE – ALL PLANTS

Plant Type	*Low*	*Low DNE*	*Med*	*Med DNE*	*High*	*High DNE*	*High Revenue as % of Low Revenue*
Coal Unscrubbed	61.9	63.8	22.0	25.4	10.1	12.1	16.37%
Coal Scrubbed	290.5	293.7	253.2	258.3	217.9	224.3	74.99%
Oil ST	770.8	771.0	769.7	769.8	769.5	769.6	99.83%
Oil CT	2.8	3.4	0.9	1.1	0.4	0.6	15.42%
Gas ST	46.4	46.7	44.9	45.1	44.6	44.7	96.21%
Gas CC	2,676.0	2,707.6	2,240.0	2,297.3	1,816.2	1,901.2	67.87%
Gas CT	21.2	22.2	11.8	12.4	9.2	9.9	43.38%
Nuclear	250.7	250.7	250.7	250.7	250.1	250.4	99.79%
Muni. Solid Waste	32.2	32.8	21.0	22.0	17.4	18.1	54.00%
Biomass	75.7	76.8	61.6	62.7	54.7	56.3	72.24%
Wind	1,134.24	1,061.88	2,221.46	2,081.24	3,253.99	3,057.07	286.89%
Hydro	76.8	76.8	76.8	76.8	76.8	76.8	100.00%
Pumped Storage	198.8	199.1	196.7	197.1	189.4	191.5	95.27%
Total	4,504.0	4,544.6	3,949.4	4,018.8	3,456.5	3,555.7	

*Includes RECs & PTC revenue

A7. EMISSIONS - PLANT TYPE

Low wind - noDNE

Plant Type	*CO2 kTon*	*SO2 kTon*	*Nox kTon*
Coal Unscrubbed	1,222.2	3.2	0.7
Coal Scrubbed	5,543.2	1.8	7.9
Oil ST	4,602.9	40.6	5.4
Oil CT	0.7	0.0	0.0
Gas ST	481.6	3.3	0.4
Gas CC	24,382.5	26.9	4.3
Gas CT	147.8	0.1	0.0
Nuclear	0.0	0.0	0.0
Muni. Solid Waste	0.0	0.1	0.1
Biomass	0.0	8.1	1.2
Wind Onshore	0.0	0.0	0.0
Wind Offshore	0.0	0.0	0.0
Hydro	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0
Total	36,381.0	84.2	20.0

Low wind - DNE

Plant Type	*CO2 kTon*	*SO2 kTon*	*Nox kTon*
Coal Unscrubbed	1,263.7	3.3	0.7
Coal Scrubbed	5,596.8	1.8	8.0
Oil ST	4,603.0	40.6	5.4
Oil CT	0.8	0.0	0.0
Gas ST	482.8	3.3	0.4
Gas CC	24,621.3	27.1	4.4
Gas CT	157.6	0.1	0.0
Nuclear	0.0	0.0	0.0
Muni. Solid Waste	0.0	0.1	0.1
Biomass	0.0	8.2	1.2
Wind Onshore	0.0	0.0	0.0
Wind Offshore	0.0	0.0	0.0
Hydro	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0
Total	36,726.0	84.4	20.2

CO2 Increase	*SO2 Increase*	*Nox Increase*
3.40%	3.69%	4.18%
0.97%	0.96%	0.55%
0.00%	0.00%	0.00%
15.18%	14.50%	14.76%
0.24%	0.13%	0.45%
0.98%	0.44%	1.74%
6.61%	4.81%	4.65%
-	-	-
-	4.80%	0.59%
-	0.09%	0.96%
-	-	-
-	-	-
-	-	-
-	-	-
0.95%	0.32%	0.82%

Medium wind - noDNE

Plant Type	*CO2 kTon*	*SO2 kTon*	*Nox kTon*
Coal Unscrubbed	374.7	1.0	0.2
Coal Scrubbed	4,842.5	1.6	7.5
Oil ST	4,600.6	40.6	5.4
Oil CT	0.2	0.0	0.0
Gas ST	475.9	3.3	0.4
Gas CC	20,747.2	21.5	3.5
Gas CT	89.4	0.0	0.0
Nuclear	0.0	0.0	0.0
Muni. Solid Waste	0.0	0.0	0.1
Biomass	0.0	8.1	1.0
Wind Onshore	0.0	0.0	0.0
Wind Offshore	0.0	0.0	0.0
Hydro	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0
Total	31,130.4	76.1	18.0

Medium wind - DNE

Plant Type	*CO2 kTon*	*SO2 kTon*	*Nox kTon*
Coal Unscrubbed	431.6	1.1	0.2
Coal Scrubbed	4,938.4	1.6	7.5
Oil ST	4,600.5	40.6	5.4
Oil CT	0.3	0.0	0.0
Gas ST	476.7	3.3	0.4
Gas CC	21,247.1	22.2	3.6
Gas CT	94.5	0.0	0.0
Nuclear	0.0	0.0	0.0
Muni. Solid Waste	0.0	0.0	0.1
Biomass	0.0	8.1	1.0
Wind Onshore	0.0	0.0	0.0
Wind Offshore	0.0	0.0	0.0
Hydro	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0
Total	31,789.0	77.0	18.2

CO2 Increase	*SO2 Increase*	*Nox Increase*
15.18%	15.41%	15.78%
1.98%	1.77%	0.88%
0.00%	0.00%	0.00%
41.75%	43.81%	45.73%
0.17%	0.09%	0.31%
2.41%	3.48%	2.69%
5.74%	3.97%	6.16%
-	-	-
-	6.36%	0.48%
-	0.09%	1.33%
-	-	-
-	-	-
-	-	-
-	-	-
2.12%	1.24%	1.16%

High wind - noDNE

Plant Type	*CO2 kTon*	*SO2 kTon*	*Nox kTon*
Coal Unscrubbed	173.0	0.5	0.1
Coal Scrubbed	4,143.1	1.4	6.9
Oil ST	4,599.6	40.6	5.4
Oil CT	0.1	0.0	0.0
Gas ST	474.7	3.3	0.4
Gas CC	16,841.4	15.7	2.7
Gas CT	74.8	0.0	0.0
Nuclear	0.0	0.0	0.0
Muni. Solid Waste	0.0	0.0	0.1
Biomass	0.0	7.9	0.9
Wind Onshore	0.0	0.0	0.0
Wind Offshore	0.0	0.0	0.0
Hydro	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0
Total	26,306.6	69.4	16.5

High wind - DNE

Plant Type	*CO2 kTon*	*SO2 kTon*	*Nox kTon*
Coal Unscrubbed	208.8	0.6	0.1
Coal Scrubbed	4,258.2	1.4	7.0
Oil ST	4,599.9	40.6	5.4
Oil CT	0.1	0.0	0.0
Gas ST	475.0	3.3	0.4
Gas CC	17,597.6	17.0	2.9
Gas CT	77.0	0.0	0.0
Nuclear	0.0	0.0	0.0
Muni. Solid Waste	0.0	0.0	0.1
Biomass	0.0	7.9	0.9
Wind Onshore	0.0	0.0	0.0
Wind Offshore	0.0	0.0	0.0
Hydro	0.0	0.0	0.0
Pumped Storage	0.0	0.0	0.0
Total	27,216.8	70.9	16.8

CO2 Increase	*SO2 Increase*	*Nox Increase*
20.69%	20.84%	21.11%
2.78%	2.48%	1.36%
0.01%	0.01%	0.00%
34.55%	32.09%	39.13%
0.07%	0.04%	0.13%
4.49%	8.01%	5.24%
3.03%	1.42%	1.35%
-	-	-
-	5.33%	0.75%
-	0.59%	3.03%
-	-	-
-	-	-
-	-	-
-	-	-
3.46%	2.08%	1.74%

A8. EMISSIONS - FUEL TYPE

Low wind - noDNE

Fuel Type	CO2 kTon	SO2 kTon	NOx kTon
Gas	25,012.0	30.3	4.7
Coal	6,765.4	4.6	7.9
Residual Oil	4,602.9	40.6	5.4
Distillate Oil	0.7	0.0	0.0
Uranium	0.0	0.0	0.0
Water	0.0	0.0	0.0
Other	0.0	8.7	2.0
Wind	0.0	0.0	0.0
Total	36,381.0	84.2	20.0

Low wind - DNE

Fuel Type	CO2 kTon	SO2 kTon	NOx kTon
Gas	25,261.7	30.5	4.8
Coal	6,860.6	4.7	7.9
Residual Oil	4,603.0	40.6	5.4
Distillate Oil	0.8	0.0	0.0
Uranium	0.0	0.0	0.0
Water	0.0	0.0	0.0
Other	0.0	8.7	2.0
Wind	0.0	0.0	0.0
Total	36,726.0	84.4	20.2

Medium wind - noDNE

Fuel Type	CO2 kTon	SO2 kTon	NOx kTon
Gas	21,312.5	24.8	3.9
Coal	5,217.2	2.1	6.9
Residual Oil	4,600.6	40.6	5.4
Distillate Oil	0.2	0.0	0.0
Uranium	0.0	0.0	0.0
Water	0.0	0.0	0.0
Other	0.0	8.6	1.9
Wind	0.0	0.0	0.0
Total	31,130.4	76.1	18.0
% over Base	16.87%	10.64%	10.89%

Medium wind - DNE

Fuel Type	CO2 kTon	SO2 kTon	NOx kTon
Gas	21,818.2	25.6	4.0
Coal	5,370.0	2.3	7.0
Residual Oil	4,600.5	40.6	5.4
Distillate Oil	0.3	0.0	0.0
Uranium	0.0	0.0	0.0
Water	0.0	0.0	0.0
Other	0.0	8.6	1.9
Wind	0.0	0.0	0.0
Total	31,789.0	77.0	18.2
% over Base	15.53%	9.65%	10.51%

High wind - noDNE

Fuel Type	CO2 kTon	SO2 kTon	NOx kTon
Gas	17,390.8	19.1	3.1
Coal	4,316.1	1.4	6.3
Residual Oil	4,599.6	40.6	5.4
Distillate Oil	0.1	0.0	0.0
Uranium	0.0	0.0	0.0
Water	0.0	0.0	0.0
Other	0.0	8.4	1.7
Wind	0.0	0.0	0.0
Total	26,306.6	69.4	16.5
% over Med	18.34%	9.55%	9.17%

High wind - DNE

Fuel Type	CO2 kTon	SO2 kTon	NOx kTon
Gas	18,149.7	20.4	3.3
Coal	4,467.1	1.5	6.4
Residual Oil	4,599.9	40.6	5.4
Distillate Oil	0.1	0.0	0.0
Uranium	0.0	0.0	0.0
Water	0.0	0.0	0.0
Other	0.0	8.5	1.8
Wind	0.0	0.0	0.0
Total	27,217	70.9	16.8
% over Base	16.80%	8.65%	8.55%

A8. FUEL PRICES AND POLUTANT CONTENT

Fuel Type	$/MBtu	kg C/MBtu
Gas	4.59	14.47
Coal	3.34	25.72
Residual Oil	12.72	21.49
Distillate Oil	23.44	21.49
Uranium	0.50	-
Water	-	-
Other	2.20	-
CO2 Charge, $/ton		-
SO2 Allowance Price, $/ton		275.90
NOx Allowance, $/ton		-
Production Tax Credit, $/MWh		23.00
NEPOOL Class 1 REC, $/MWh		40.00

	SO2 lb/Mbtu	Nox lb/Mbtu
Coal Unscrubbed	0.50	0.11
Coal Scrubbed	0.06	0.24
Oil ST	1.39	0.18
Oil CT	0.84	0.95
Gas ST	0.73	0.09
Gas CC	0.12	0.02
Gas	0.04	0.02
Nuclear	0.00	0.00
Muni. Solid Waste	0.01	0.02
Biomass	0.79	0.11
Wind Onshore	-	-
Wind Offshore	-	-
Hydro	0.00	0.00
Pumped Storage	0.00	0.00

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