THE EFFECTS OF INTEGRATING WIND POWER ON TRANSMISSION SYSTEM PLANNING, RELIABILITY, AND OPERATIONS

Draft Report on Phase 1:

Preliminary Overall Reliability Assessment

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FOREWARD

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1. INTRODUCTION

1.1 BACKGROUND

In response to emerging market conditions, and in recognition of the unique operating characteristics of wind generation, the New York State System Operator (NYISO) and New York State Energy Research and Development Authority (NYSERDA) commissioned a joint study to produce empirical information that will assist the NYISO in evaluating the reliability implications of increased wind generation.

The work is divided into two phases.

Phase 1, Preliminary Overall Reliability Assessment. This initial phase is a preliminary, overall, screening assessment of the impact of large-scale wind generation on the reliability of the New York State Bulk Power System (NYSBPS). It provides the foundation for a detailed system performance evaluation that will follow. This assessment includes:

- **Review of world experience with wind generation**, focusing on regions that have integrated significant penetration of wind resources into their power grids. This task identifies critical issues related to large-scale wind generation, reviews approaches and solutions being implemented by network operators, identifies industry best practices and technology trends, and summarizes lessons learned with respect to their relevance for the NYSBPS.
- **Fatal flaw power flow analysis** to determine the maximum power output at prospective wind generation sites that can be accommodated by the existing transmission system infrastructure, considering thermal ratings of transmission lines.
- **Reliability analysis** to determine the contribution of prospective wind generation towards meeting New York State requirements for Loss Of Load Expectation (LOLE).
- **Review of current planning and operating practices** to identify New York State Reliability Council (NYSRC), Northeast Power Coordinating Council (NPCC), North-American Electric Reliability Council (NERC), and NYISO rules, policies, and criteria that may require modification to be compatible with high penetration of wind generation.

Phase 2, System Performance Evaluation. This phase will involve a detailed system performance evaluation of the impact of large-scale wind generation on the NYSBPS, leading to recommendations for any necessary modifications to existing procedures and guidelines to reliably accommodate the integration of the new wind generation.

The results of the **Preliminary Overall Reliability Assessment** that follow provide a preliminary assessment of the ability of the NYSBPS to reliably accommodate the penetration of large-scale wind generation on the order of that expected under an RPS.

1.2 DATA

Technical information and data for this study was provided by several sources. NYISO provided power flow datasets, contingency lists for the NYSBPS, and NYSRC reliability datasets. Crucial data related to wind generation technology, forecasting, and prospective New York State wind generation sites was provided by AWS Scientific, Inc., a separate contractor providing services to NYSERDA for this project. Generation fuel cost and heat rate data from the preliminary NYSDPS RPS analyses were also employed for this phase of the assessment.

1.3 STATUS

Phase 1 of this project was conducted in November and December of 2003, and the results are presented in this report. Phase 2 is scheduled for completion in late 2004.

2. EXECUTIVE SUMMARY

2.1 OVERVIEW

NYSERDA and NYISO commissioned this study to evaluate the impact of large-scale wind generation on the planning, operation, and reliability of the New York State Bulk Power System (NYSBPS). The study is being conducted in two phases:

- Phase 1: Preliminary Overall Reliability Assessment
- Phase 2: System Performance Evaluation

Phase 1 has been completed and results are summarized in this report.

2.2 DATA ON NY STATE WIND RESOURCES

AWS Scientific, Inc., provided two critical data sets that enabled much of the analysis conducted during Phase 1.

- **Potential Wind Generation Capacity**. A total of 101 prospective wind generation sites in NY State were identified, with a total generation capacity of 10,026 MW. Data for each site included total wind generation output in MW, capacity factor, and the nearest existing transmission substations.
- **Hourly Wind Profiles**. For each of the 101 prospective sites, this data included statistically derived hourly power output in MW for a full calendar year.

Figure 2.1 shows geographic distribution of the potential wind sites with respect to the eleven zones within the New York Control Area (NYCA).

Potential Wind Generation by Zone	
Zone A	4016 MW
Zone B	515 MW
Zone C	922 MW
Zone D	433 MW
Zone E	2683 MW
Zone F	703 MW
Zone G	154 MW
Zone H	0 MW
Zone I	0 MW
Zone J	0 MW
Zone K	600 MW
Total	10026 MW

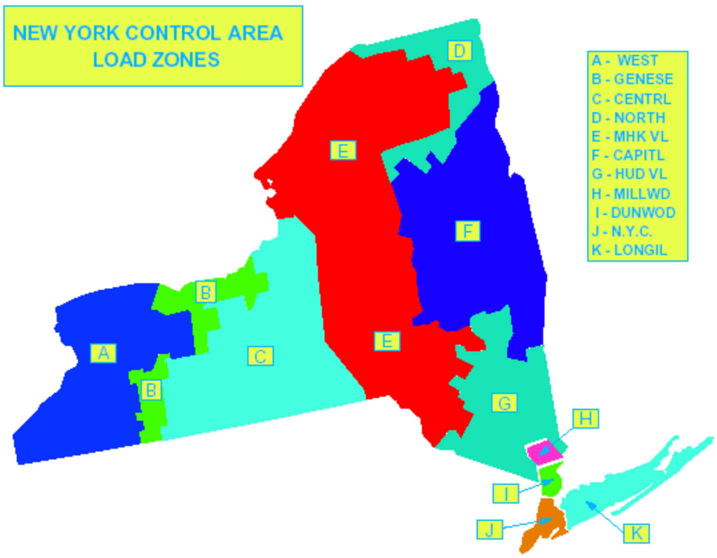

Figure 2.1. New York Control Area Load Zones, and Potential Wind Generation

AWS Scientific also provided technical reports relating to wind generation, including

- Wind Generation Technical Characteristics for the NYSERDA Wind Impacts Study
- Overview of Wind Energy Generation Forecasting

These reports are presently in draft form, and will be released in February 2004.

2.3 WORLD EXPERIENCE WITH WIND

Several regions of the world that have integrated substantial penetration of wind resources were evaluated with the objective of identifying lessons learned and best practices applicable to New York State. Some of those regions are listed in Table 2.1.

Table 2.1 Example systems with high penetration of wind resources

	Peak Load	Installed Wind	Penetration
Eltra (Denmark)	3.8 GW	2.3.GW	62%
Germany	78 GW	12 GW	15%
Spain	33 GW	4.8 GW	15%
PNM (New Mexico)	1.5 GW	0.2 GW	14%
ERCOT (Texas)	63 GW	1.9 GW	3%

2.3.1 Emerging Best Practices on Interconnection Requirements

New York State should adopt some of the requirements that have grown out of the experiences of other systems. Specifically, New York State should require all new wind farms to have the following features:

1. Voltage regulation at the Point-of-Interconnection, with a guaranteed power factor range.
2. Low voltage ride-through.
3. A specified level of monitoring, metering, and event recording.
4. Power curtailment capability.

These features are implemented in wind farms around the world, and are proven technology. The following features are emerging in response to system needs. They are in early development, and should be required by New York State in the future as they become available.

5. Ability to set power ramp rates
6. Governor functions
7. Reserve functions
8. Zero-power voltage regulation

New York State may also wish to consider a minimum wind farm size, on the order of 5 to 10 MW, below which the local transmission operator may waive some or all of these requirements on a case-by-case basis.

2.3.2 Centralized Forecasting

For secure operation of the power system, it is essential that the system operator have wind power production forecast information for all wind facilities. Forecasts of the hourly production for each individual wind farm are required, at least, for day-ahead planning, and may be valuable for short-term operations decisions as well. The combined forecasts will tend to reduce the operational importance of small local errors in wind generation predictions for individual facilities. With central collection of forecasts, major weather events and the problems they might cause can be anticipated at the system operator level. Regardless of whether responsibility for forecasting power production resides with individual wind facilities or a centralized system, a center to collect, distribute, archive and possibly enhance forecast information should be established for New York State.

2.3.3 Evolution of Technology and Procedures

New York State must recognize that both wind technology and practices are maturing quickly. The regulating and operating entities must maintain institutional flexibility that allows the adoption of new procedures. System operators have learned how wind generation affects the particular characteristics of their systems. This will undoubtedly be the case for New York State, which should begin documentation of operating experience now. Gathering experience in the near term, while wind penetration is low, will increase confidence for future operation with higher levels of penetration.

2.3.4 Operations Impacts

The largest impact of wind generation on New York State system operations is expected to be on load following reserves and unit commitment. Impact on regulation is not expected to be substantial. The addition of wind generation increases the net load variability. The preliminary analysis shows that the addition of 3300 MW of wind generation will increase the net New York State load variability by about 6% (from 920 MW to 975 MW). This increase in variability is not expected to create significant operating problems. At this level of penetration, any rapid drop in production from the wind farms is not expected to exceed the existing limiting contingency that determines the 10-minute operating reserve (1200 MW) for the state. This preliminary analysis provides insight into the expected level of hour-to-hour variability that might accompany wind generation. It does not provide the detail necessary to make an assessment of the expected impact on hourly and daily operations. In Phase 2, the variability of selected sites will be investigated further, including consideration of intra-hour, diurnal, monthly and seasonal impacts.

Critical objectives for the next phase of this project include developing a better understanding of New York State requirements and practices with respect to:

- Load following and regulation, and the impact of wind generation variability.
- Unit commitment, and the impact of wind forecasting accuracy.

2.3.5 Penetration Limits

World experience indicates that New York State should be able to integrate wind generation to a level of at least 10% of the system peak load – a total of about 3300 MW of wind turbine-generators. The experiences of the example systems provide a good foundation on which to make this preliminary assessment. At this level of penetration, there should be no substantial operational limits or problems, provided New York State adopts wind farm requirements and operations practices as described above.

Some other systems have experienced unexpectedly rapid increases in wind penetration. New York State should be able to accommodate any rate of wind generation additions at least up to this level of penetration without substantial operational limits or problems.

2.4 FATAL FLAW POWERFLOW ANALYSIS

The survey of world experience with wind generation indicated that New York State should be able to accommodate at least 10% penetration. The primary objective of the fatal flaw power flow analysis was to determine whether the existing New York State transmission system could accommodate this level of wind generation. Specifically, the goal was to determine the maximum power output at each of the 101 prospective wind generation sites in various regions of New York State with the existing transmission system infrastructure. The analysis focused solely on the thermal impact of the prospective wind generation on the transmission network. No transmission reinforcements were evaluated.

The local contingency analysis restricted the maximum amount of wind generation at each site such that pre- and post-contingency branch loadings were within thermal rating criteria, given the existing transmission system. The results show that of the approximately 10,000 MW of prospective wind generation, the transmission system can accommodate about 5,800 MW under 80% peak load system conditions, and about 6,100 MW under light load (44% of peak) conditions.

Existing generation was redispatched to compensate for the addition of new wind generation in each zone. The majority of generation available for redispatch in Zones B and C (Areas 2 and 3) was nuclear generation. If the nuclear plants are treated as both must-run and non-dispatchable, then the maximum wind generation under 80% peak load conditions would be reduced to about 5,100 MW. Similarly, the maximum wind generation under light load conditions would be reduced to about 4,900 MW.

In general, the preliminary transmission system analysis showed that the impact of the additional wind generation was mixed. It improved thermal performance in response to some outages and reduced it in response to others. Additional analysis would be required to determine the relative impact due to each wind generation project and the associated redispatch, as well as any mitigation requirements.

In summary, although some local sites may be restricted, the fatal flaw powerflow analysis did not preclude the system from reaching the 10% level of penetration discussed above.

2.5 RELIABILITY ANALYSIS

This analysis examined the impact of progressively increasing levels of wind turbine additions on the interconnected reliability of the New York Control Area (NYCA) as measured by Loss of Load Expectation, LOLE. While their average capacity factors were about 30% the capacity values based on their intermittent generation characteristics was only about 10% of their nameplate ratings.

Wind turbines demonstrate definite seasonal and diurnal output characteristics and the existing UCAP calculations should be modified to reflect that fact. Wind generation patterns within New York State demonstrate much lower levels of output in the summertime (Figure 2.2), and within the day they tend to peak in the morning, with afternoon and evening outputs roughly half of the morning levels (Figure 2.3). This provides little reliability value to a system that typically experiences its greatest need for capacity in late afternoon and early evening in the summer. A modification of the UCAP calculations based on the expected capacity factor during peak intervals provides UCAP values much more in line with actual reliability impacts.

Due to the current generation and transmission configuration within New York, additional capacity added west of the Central East Interface provides only a fraction of the reliability value as compared to capacity added downstate. Since location is not a factor when evaluating the UCAP of conventional generation it should not be used to penalize wind. However, it is something that needs to be kept in mind since 85% of the potential sites identified in this analysis fall west of this interface.

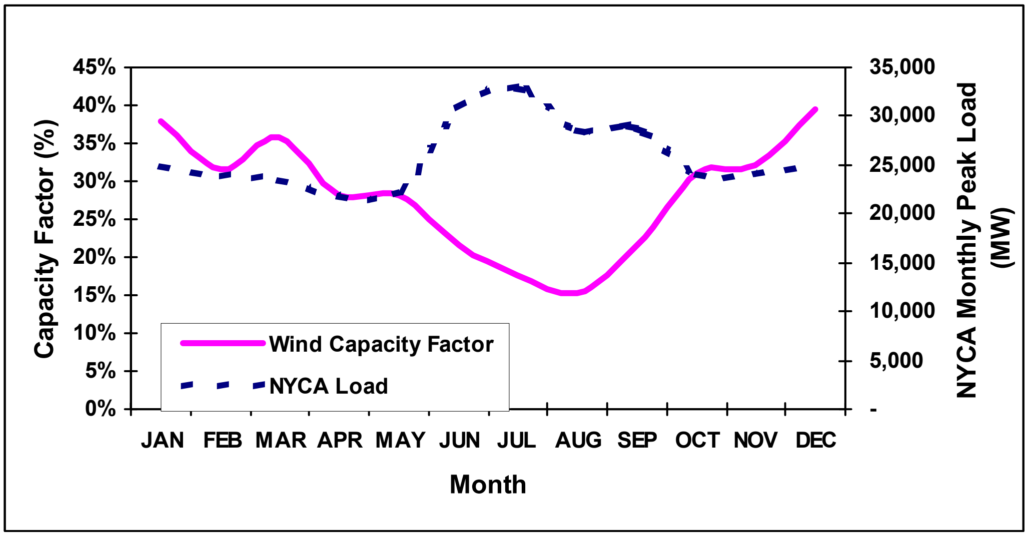

Figure 2.2 Average monthly capacity factor for all 101 wind sites and NYCA monthly peak load

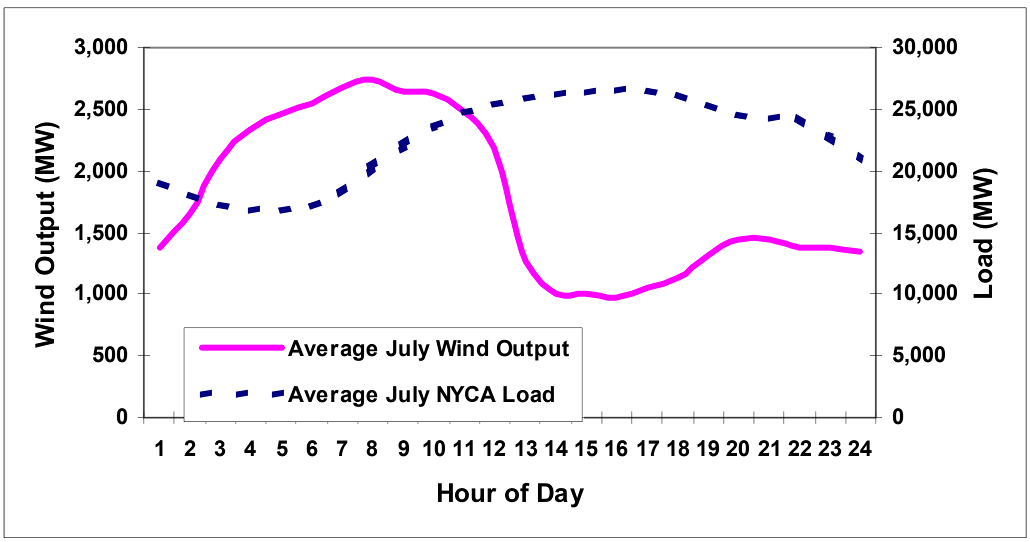

Figure 2.3 Average hourly output for all 101 wind sites and NYCA average load for July

Although it may provide minimal benefit, the addition of wind generation, in and of itself, will not cause the reliability of the system, as measured by LOLE, to degrade. However, if existing, marginally operating, thermal generation is retired, or if expected new generation is deferred or cancelled as a result of wind additions then system reliability will be negatively impacted, although the NPCC minimum reliability threshold of 0.1 days/year LOLE will always be maintained. Phase 2 of this study will examine more of the operational impacts of wind generation, including the impact on spinning reserve, unit commitment and the change in cycling duty and capacity factors of thermal generation.

2.6 NEW YORK STATE PLANNING AND OPERATING PRACTICES

This review of the reliability rules for the planning and operation of the NYSBPS shows that, in general, the rules as written do not need to be modified to account for the presence of significant wind generation in the state. However, some of the procedures and the planning and performance criteria definitions referenced in the rules may have to be examined and possibly modified. Specifically, the following procedures may need to be modified:

- Calculation of operating reserves, regulation and load following requirements in the presence of wind generation
- Calculation of unforced capacity value of wind generation
- Consideration of wind generation in transmission planning
- Test requirements for the Dependable Maximum Net Capacity (DMNC) measurement of wind generation
- Operating procedures for operation with impending severe weather conditions

From an operational standpoint, it is not essential to update any of these procedures immediately in order to proceed with the integration of new wind generation projects in the State. However, all of these procedures will need to be updated before significant wind penetration levels are achieved.

Some procedures may need to be updated sooner than others in order to facilitate the planning of the system. For instance, the procedure for calculating the UCAP for wind generators will need to be updated before capacity credits can be issued to wind generators. This will also be critical to wind developers, as capacity payments are a factor in determining the economic feasibility of prospective wind projects. Also, operating procedures with severe weather conditions and the rules for calculating operating reserves, regulation and load following requirements will need to be updated.

This is a preliminary review that will be revisited in Phase 2, where the evaluation will be made in light of the complete findings of the study.

2.7 CONCLUSIONS

The results of this preliminary assessment indicate that New York State should be able to integrate wind generation distributed across the NYCA to a level of at least 10% of the system peak load (a total of about 3300 MW of wind turbine-generators) without significant adverse impacts on the planning, operations, and reliability of the bulk power system. This conclusion is based on the experience of other systems with significant penetration of wind resources, and is further supported by the results of the fatal flaw power flow analysis and the reliability analysis of the NYSBPS.

Phase 2 of this study will evaluate the impact of wind generation on planning and operation of the NYSBPS in more detail, and refine the conclusions from this preliminary assessment.

3. WORLD EXPERIENCE WITH WIND GENERATION

3.1 WORLD EXPERIENCE – PENETRATION

Wind generation is the fastest growing source in many power systems around the world. Some power systems, most notably in Western Europe and the central and western portions of the U.S., have incorporated significant amounts of wind generation into their systems. Table 3.1[i] shows the worldwide wind generation installed base, including the additions for year 2002. Many of these systems have experiences that are relevant to New York State. In the following section 3.1.1, a selection of the systems with significant wind resources is discussed. The example systems are not intended to be a comprehensive review of the entire world, but rather they were chosen for their wind experience and relevance to New York State. This review is preliminary. Some data for the selected example systems has been estimated and will be confirmed as this effort continues in Phase 2.

This initial discussion is focused on providing insight into the magnitude of wind penetration in the selected systems and how they compare to the characteristics of NYSBPS. Such comparisons are valuable, even though each power system has its own particular characteristics that make perfect side-by-side comparisons difficult, if not impossible. In subsequent sections an examination of the specific characteristics and experience that is relevant to New York State will be provided.

Table 3.1. Global Wind Generating Capacity

Global Wind Energy Generating Capacity (AWEA and EWEA estimates)

Wind Energy Markets* (by installed capacity, in MW)	2001 Year End Total	2002 Additions	2002 Year End Total
Country			
USA	4,275	410	4,685
Canada	198	40	238
North America	**4,473**	**450**	**4,923**
Germany	8,754	3,247	12,001
Spain	3,337	1,493	4,830
Denmark*	2,489	497	2,880
Italy	682	103	785
Netherlands*	486	217	688
UK*	474	87	552
Sweden	293	35	328
Greece	272	4	276
Portugal	131	63	194
France	93	52	145
Austria	94	45	139
Ireland	124	13	137
Belgium	32	12	44
Finland	39	2	41
Luxembourg	15	1	16
EU Total	**17,315**	**5,871**	**23,056**
Norway	17	80	97
Ukraine	41	3	44
Poland	22	5	27
Latvia	2	22	24
Turkey	19	0	19
Czech Republic	6.8	0.2	7
Russia	7	0	7
Switzerland	5	0	5
Hungary	1	1	2
Estonia	1	1	2
Romania	1	0	1
Other Europe	**123**	**112**	**235**
India	1,507	195	1,702
Japan	275	140	415
China	400	68	468
Australia	72	32	104
Egypt, Morocco, Costa Rica, Brazil, Argentina, others	225 (est.)		225 (est.)
Other Total	**2,479**	**435**	**2,914**
World Total	**24,390**	**6,868**	**31,128**

****The difference between end 2001 and end 2002 figures is 6,738 MW. The discrepancy of 130 MW is due to decommissioning in Denmark (106 MW), Netherlands (15 MW), UK (9MW***

3.1.1 Example Systems

The following systems are used to provide examples throughout the balance of this report. The reference number provides the primary source of data used in the supporting figures, although other sources referenced in the document were used as well.

1. Eltra[ii]
2. Germany[iii]
3. Spain[iv]
4. New Mexico[v]
5. Minnesota[vi]
6. ERCOT[vii]

The three European systems top the list in terms of total wind generation, and have been the technology leaders as well. Worldwide, the majority of wind turbine-generator (WTG) manufacturing companies started and have substantial manufacturing capability in these first three countries[1]. Topologically, the bulk transmission grid of each of these systems has aspects that are of interest to New York State.

The three U.S. systems, besides significant penetration, have other characteristics of interest: New Mexico has a quite high relative penetration and Public Service of New Mexico's (PNM) has driven one important aspect of new wind generation technology. Figures provided below in reference to New Mexico are primarily specific to PNM. Minnesota has long term operating experience, provides significant support of wind research, and has some topological similarities to NYSBPS. Figures and reference for Minnesota are primarily for Xcel North (still referenced as Northern States Power – NSP, in many sources). The Electric Reliability Council of Texas, ERCOT, operates a system with substantial penetration and is a particularly active ISO, leading the industry on practice and policy. Some specific references are included to the TXU Energy system, which serves a large portion of Texas and includes significant wind generation. There is much to be learned from these three domestic systems.

Some data in the figures was also obtained from GE MAPS databases developed from public domain data.

[1] Vestas, Bonus – Demark; GE Wind, NEG Micon, Enercon, Nordex, Repower – Germany; Gamesa, MADE, Ecotecnia - Spain

Figure 3.1 shows four key measures for New York State and the six example systems. The totals for wind are the sum of all installed wind generation based on nameplate power. For New York State, the present NYISO limit of 500MW is used for illustration. The tie line figures are based on thermal, not operational, capability. They are discussed further below. New York State is bounded by the example systems, in terms of generation, load, and tie line capability.

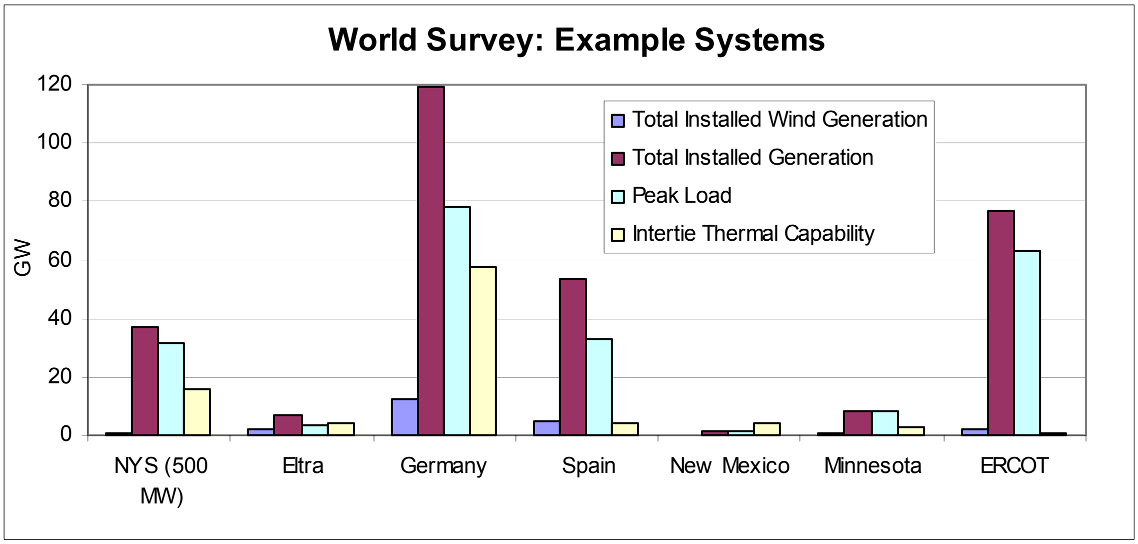

Figure 3.1 Survey of Example Systems

3.1.2 Normalized Comparisons to New York State

The totals shown in Figure 3.1 give an indication of the overall size of the example systems and their total installed wind generation. However, it is difficult to make comparisons between the systems based on these widely varying figures. Common bases of comparison are needed. One key measure of the influence of wind on a power system is "penetration." In general terms, this is the amount of wind generation compared to the size of the system. There are different ways of quantifying the size of a system, each of which provide a somewhat different view.

Two such indices are total installed capacity and peak load. The measures of installed capacity vary. New York State uses unforced capacity (UCAP), rather than installed capacity (ICAP) because it provides a better measure of the capacity that is actually usable for the system. Unfortunately, UCAP data for other systems is unavailable, and so we have used ICAP. ICAP alone has the potential to introduce distortion into the picture, as different systems (especially in a global comparison) have different philosophies and policies regarding capacity margins, retirements, etc. (e.g., Germany and Spain have installed capacity more than 50% over their peak load). The total load served is in many respects a better indicator of system size. Figure 3.2 shows the total installed wind generation normalized to (divided by) peak load, and converted to percent. Again, for New York State, the present NYISO threshold of 500MW is used for illustration. On this basis, for New York State a 10% penetration in 2008 would correspond to about 3,300MW of installed wind generation.

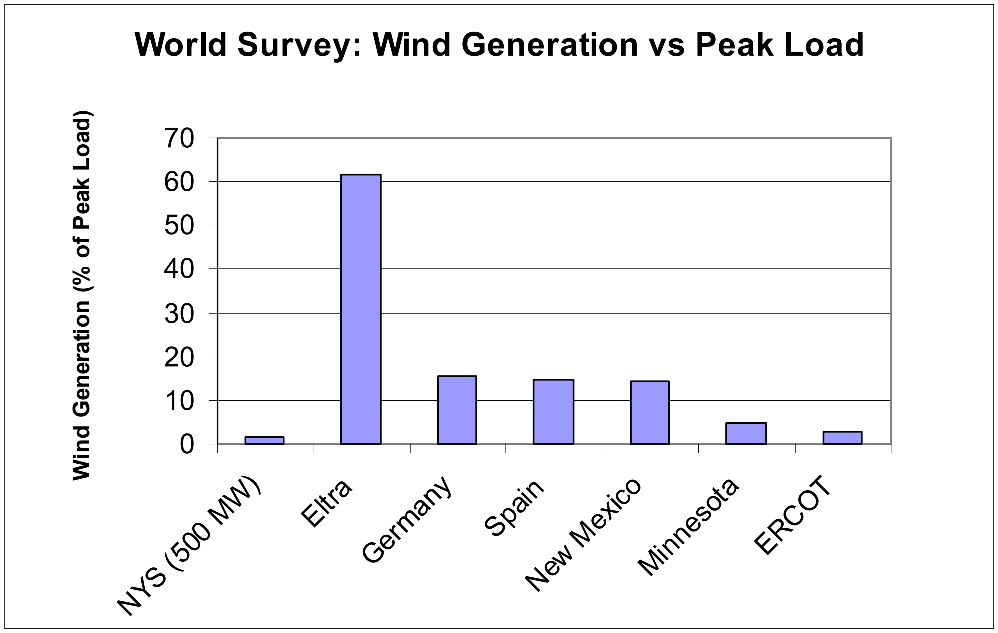

Figure 3.2 Survey of Example Systems: Normalized to System Peak Load

The selected example systems have electrical ties to neighboring systems. The relative strength of those ties is another key measure in quantifying the resilience of the system to disturbances. Providing a meaningful and comparable measure of intertie strength is challenging. One relatively unambiguous, but imperfect, index is the total normal thermal capacity of the ties. This index has the virtue that comparable data is available, and because system specific nuances of actual transfer limits are not required. For most systems, including New York, this measure substantially over-states the exchange capability, since simultaneous constraints are not reflected. There are likely constraints due to system stability, voltages and contracts that reduce this total. Nevertheless, as the examples will show, the presence of tie lines can be a key factor in determining system performance and security with significant penetration of wind. The system tie line capabilities are shown in Figure 3.1, and the capabilities normalized to system peak load are shown in Figure 3.3.

This tieline data is based on available sources, and is not perfectly consistent between systems. The ties from Eltra are a mixture of AC and DC transmission. The neighboring systems, Norway, Sweden and Germany are all significantly bigger than Eltra. The tie capacity for Eltra is based on published transfer capability, and probably understates the thermal capability. The totals for Spain are for connections to France and Morocco, and do not include the relatively tight ties to Portugal. Portugal is quite tightly tied to Spain and also has significant wind generation, so the two systems tend to act together. All of the ties from ERCOT are asynchronous DC links that are used for energy exchange and not regulation. The bar for Minnesota is estimated based on NSP maximum import of about 2,600MW, and may understate thermal capability. Of the example systems, Spain and ERCOT have the least intertie capability.

Other comparative measures of interest include: generation resource mix, intertie operational limits and directional capacity, and minimum load. It is not uncommon for periods of high wind to coincide with minimum system load. Under these conditions it is possible for a much higher percentage of system load to be served by wind than is suggested by Figure 3.2. In Phase 2, further investigation of system minimum load conditions is planned.

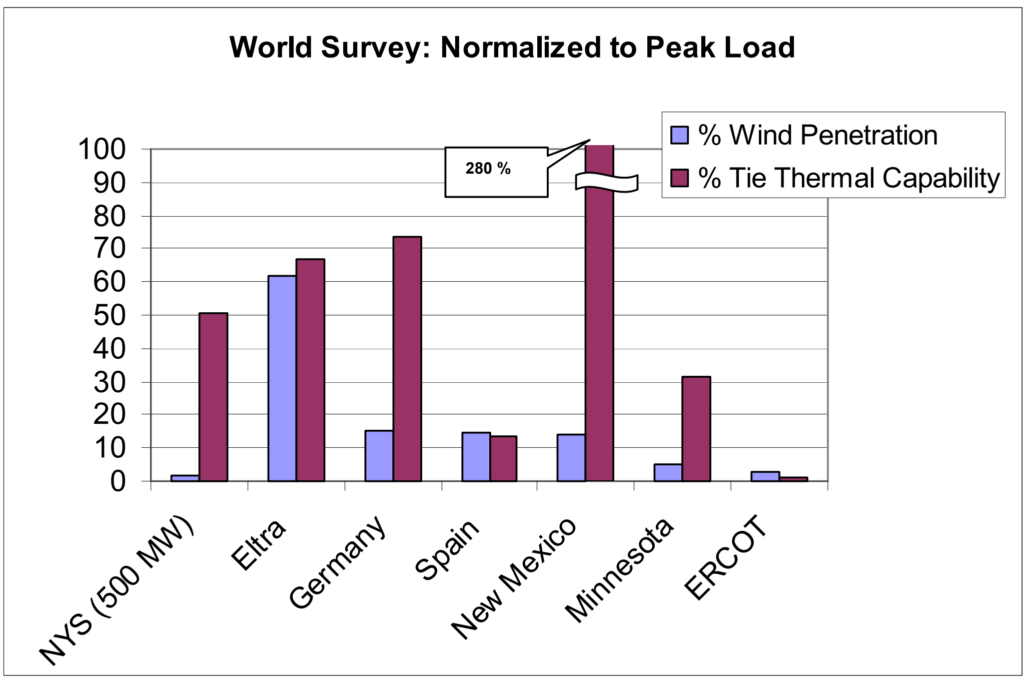

Figure 3.3 Survey of Example Systems: Normalized Tie line Thermal Capacity

3.1.3 Observations

The example systems have significant amounts of operating wind generation. The three European example systems have years of successful operating experience at penetration levels greater than ten percent. The U.S. example systems have lower penetration and less operating history. The strength of interties with neighboring systems varies considerably. Of the example systems, Spain and ERCOT have the weakest ties to their neighbors. Overall, these systems provide a range of size and tieline strength that bounds the New York State system.

3.2 PLANNING

This section delves into planning practice, and will be the first of several sections that discuss lessons learned. The next major section examines system operations. Some aspects of wind generation impact both. For those issues we have placed them in the most appropriate section, to avoid repetition.

In the following discussions, the distinction between individual wind turbine-generators (WTGs) and entire wind farms is important. The worldwide trend in major wind generation developments is towards wind farms. Wind farms are made up of anywhere from a few to hundreds of individual WTGs. The individual WTGs are located within a site taking into account such considerations as wind characteristics, land topology, minimum WTG separation, visual impacts, etc. The power generated by each individual WTG is injected onto a dedicated electrical “collector” system. This collector system resembles a utility power distribution system in reverse, and typically operates at distribution voltages (34.5kV is common in the U.S. for larger farms; 12.5 kV for smaller farms). The collector system is owned by and dedicated to the wind farm. Other utility customers are not served from it. The collector system converges at single point, where a substation with one or more dedicated transformers steps the voltage up to the transmission system. The power from the farm is injected into the host grid at a single point, in essentially the same fashion as other conventional thermal and hydro generation. This point, variously called the point of interconnection (POI) or the point of common-coupling (PCC), is normally where ownership changes hands, where power metering takes place, and where communications between the wind farm and the system operator meet. What takes place within the farm is normally the concern of the farm operator, in the same sense as for the operation of a conventional plant.

Individual WTGs within a farm have a degree of local, autonomous control. There are significant variations between vintage, type and manufacturer. Most WTGs can start, stop and manage their power/speed behaviors without supervision. In wind farms, it is common to have a centralized SCADA (system control and data acquisition) system. For many new farms, especially larger ones, there is also farm level supervisory control. The supervisory control monitors the individual WTGs, senses grid conditions, receives instructions from the system operator, and distributes commands to the individual WTGs. Again, the functionality of these supervisory controls varies considerably.

Dispersed wind generation, in which a single machine is connected to the host utility distribution system that feeds other customers, is relatively uncommon (a small fraction of the wind generation installed, or being installed) in the U.S. In comparison, the example European countries all have significant amounts of such dispersed wind generation. Such dispersed installations typically have simpler controls and may have little or no real-time communications with the system operator.

In the following discussions, planning and operations issues are primarily driven by the overall behavior and response of entire wind farms. Design for wind integration is a system design problem; not just a question of connecting large numbers of individual WTGs.

3.2.1 Wind Resource Functional Requirements

A companion report, "Wind Generation Technical Characteristics for the NYSERDA Wind Impacts Study,"[viii] documents the characteristics of individual WTGs and of wind farms, which vary considerably. From the perspective of grid planning and operation, equipment characteristics can vary across a spectrum from relatively disruptive to grid friendly.

3.2.1.1 Statutory Requirements

Acceptance and qualification of new generation resources for interconnection is handled by entities responsible for planning and approving system expansions. There is a range of practices around the world and across the example systems.

In Europe, the rules governing the interconnection of new resources are broadly termed "grid codes." These grid codes have subtle differences in detail and application philosophy. In general terms, European grid codes tend towards relatively detailed specification of equipment characteristics. For example, new generation resources have to meet very specific requirements for operation at off-nominal voltage and frequency.

Compared with European grid codes, U.S. practice tends to be focused somewhat more on overall system performance and less on details of equipment behavior. Interconnection of new resources in most U.S. systems (including New York State) must pass a battery of system impact evaluations geared towards determining and mitigating any adverse system impacts that might result from interconnection. This approach tends to drive a more customized functionality for interconnection of new resources. Philosophically, the European grid codes take the approach that installations which meet these equipment specifications are generally expected to meet the system needs.

European grid codes, which have evolved over many years of practice around conventional generating resources, have significant deficiencies in addressing the particular, distinct characteristics of wind generation. There are two results of these deficiencies that are relevant for New York State. First, in many instances, these interconnection requirements have been found to be at odds with the technical reality of wind generation. This has resulted in *derogations*, project specific exemptions to clauses in the particular grid code. Second, several European systems are leading substantial and aggressive efforts to update their grid codes to more realistically account for wind generation, and reduce the need for derogations. These emerging grid codes are primarily focused on demanding features that are grid friendly, while attempting to make requirements that are physically (and economically) practical with available or nearly available technology. They are forcing both WTG manufacturers and wind farm developer/designers to raise their targets in terms of performance and functionality. The ESB National Grid effort to improve their grid code has taken the noteworthy step of conducting a sequence of workshops to solicit inputs from all stakeholders, including equipment manufacturers, developers, advocacy groups and regulators.

In the U.S., performance and practice for integration of wind generation has been driven by requirements derived from specific applications. A few relevant projects that have pushed wind farm functionality toward increased grid compatibility are discussed below. Much of the functionality emerging from these specific applications mirrors, or at least resembles, the features and requirements emerging from the European grid code development activities.

The net result is a certain degree of convergence in practice. In fact, the American Wind Energy Association (AWEA) and the Western Energy Coordinating Council (WECC) have active programs aimed at producing recommendations for standard practices (i.e., grid codes) for interconnection of wind generation.

3.2.1.2 Voltage Regulation

As the companion "Technical Characteristics" document describes, the reactive power behavior and the ability of WTGs and wind farms to regulate voltage varies. Historically, WTGs with induction generators have not been required to participate in system voltage regulation. Their reactive power demands, which increase with active power output, are typically compensated by switched shunt capacitors. This compensation is somewhat coarse, in that the capacitors are switched in discrete steps with some time delay. Thus, the compensation is neither smooth nor fast enough to cover all dynamics of interest.

This approach can be satisfactory for relatively small wind farms (i.e., small compared to the strength of the local transmission system to which they are connected). As wind farms have grown with locations in relatively weak transmission systems, this approach has proven to be unacceptable in some cases. Many (if not all) of the large wind farms in the three example U.S. systems are designed to provide voltage regulation. These farms include supervisory controllers that instruct components of the wind farm (WTGs, shunt capacitors, etc.) to regulate voltage, usually at the POI, to a specified level. Many new wind farms accept a reference voltage that is supplied remotely by the system operator.

There are three classes of WTGs described in the "Technical Characteristics" document: stall regulated, scalar controlled and vector controlled. Of these three types, only vector controlled WTGs have the inherent ability to control reactive power output from the generator, and therefore to regulate voltage. For the other types of WTGs, additional equipment, such as the capacitors mentioned above, are required to compensate the generator reactive power consumption and to meet the reactive power needs of the host grid. In applications with relatively weak systems, wind farms with these types of machines may require the addition of solid-state reactive power equipment to meet the voltage regulation requirements. For example, applications of stall-regulated machines in Wyoming (PacifiCorp Foote Creek) and South Australia (Starfish Hill) were provided with such devices (a STATCOM, specifically an AMSC DVAR in Wyoming, and a conventional static var compensator – SVC – in South Australia).

The power factor range of a wind farm is a function of the characteristics of the component WTGs, the collector system and other equipment in the farm. From a systems perspective, the available power factor range as measured at the POI is important. In the U.S., most wind farm interconnection agreements specify a required power factor range. In many cases, the power factor range requirement is determined by the particular needs of the site (i.e., grid characteristics at the POI). There is no clearly emerging consensus in the U.S. on required power factor range. Ranges of ± 0.95, +0.95/-0.90, and ± 0.90 are all used. Occasionally, unique application-specific ranges are specified.

Practice in Europe has been, and largely remains, power factor control – usually power factor neutral. Tight grids in Europe mean that voltage regulation problems of the type the U.S. experiences in weak areas are uncommon. The prospect of integrating large offshore wind farms that are radially connected to the host grid by tens of miles of underwater cable is changing the present practice. European offshore wind farms are beginning to provide voltage regulation.

The bottom-line is that, for the most part, fast and tight voltage regulation is possible with a properly designed wind farm. As the companion "Technical Characteristics" document explains, the choice of WTG technology plays an important role. Virtually any type of WTG technology can be successfully applied, but WTGs without built-in voltage regulation capability may require external voltage-regulating devices such as SVC or STATCOM. For large wind farms, the obvious policy is to require that wind farms be capable of providing voltage regulation. New York State may wish to set a minimum rating (or SCR) below which voltage regulation requirements are set less stringently. The required range of power factor may have significant cost implications for the developers. Setting a minimum standard of performance (e.g., ± 0.95,) with the option to require a larger range, if an application requires it, is one reasonable approach.

3.2.1.3 Low Voltage Ride Through

The ability of WTGs to tolerate momentary depressions in system voltage due to system faults is an area of intense interest in the wind industry. Requirements and corresponding features in WTGs, variously called "fault ride-through," "low voltage ride-through" (LVRT), and "emergency voltage tolerance" have emerged in the past year or so as a major technology issue for wind generation.

Historically, the utility industry has expected that wind generation will trip offline in response to significant system disturbances. This expectation (and often requirement) was driven by three considerations that are no longer generally true:

1. Wind generation constituted a small portion of the total power resource for utilities. The contribution of wind to overall system security was minimal or nonexistent. Thus, there was no pressing system need to keep wind generation running following the occasional disturbance.

2. Much (if not most) wind generation was distributed throughout utility distribution systems. Generally, it is undesirable and potentially hazardous for generation imbedded in distribution systems to continue operation through or after system disturbances. The principal concern is the inadvertent creation of uncontrolled, but energized electrical islands. These islands present a risk to both personnel and equipment.
3. It was technically difficult for the WTG manufacturers to provide equipment that could remain online through significant system disturbances, especially deep voltage dips.

All three of these considerations have changed, and been replaced by a significant concern. When faults occur on the transmission lines of any system, the voltage is depressed for a large geographic and electric area. This is particularly true of faults on the trunk lines (e.g., New York's 345kV system). Since voltage is depressed over a large area, all WTGs that are sensitive to these voltage depressions will trip. Systems around the world have found that as the penetration of wind generation increases their exposure to significant simultaneous loss of wind generation is a growing concern.

In the U.S., the risk of the loss of wind generation drove Public Service of New Mexico (PNM) to require LVRT on the new 208MW Taiban Mesa (New Mexico Wind) Project. For this project, PNM faced the risk that the farm might trip for faults essentially anywhere on the 345kV system in the state. Their concern was increased by proposals for huge amounts of additional wind projects in New Mexico in the near future. The LVRT specification (i.e., minimum voltage and duration) for that project was determined based on the particular requirements of that site. The Taiban Mesa project, which is now in commercial operation, is believed to be the first U.S. farm with LVRT.

Similar concerns have emerged in Europe, especially Spain. The Spanish grid is more vulnerable because is has (a) relatively high wind penetration, (b) relatively tight EHV grid – faults are felt everywhere, and (c) relatively weak interconnection to neighbors.

E-ON Netz, the major German transmission operator, has introduced an LVRT grid code[ix] that is receiving wide acceptance. This grid code is serving as a template for similar requirements emerging from nearly every country with wind generation.

Figure 3.4 shows a composite of a survey (performed for GE Wind Energy) of actual and proposed LVRT grid codes. The figure shows the amplitude and duration of voltage deviations that must be tolerated by WTGs to meet all of the surveyed grid codes. Each labeled segment in the composite represents the most stringent demand of all the surveyed countries. Some segments are extreme, and cannot normally be met by conventional generation resources. As noted, these LVRT requirements are the subject of intense scrutiny and debate in the industry. Some, most notably the e-ON specification, are considered to be settled. Others are still very much works in progress. In the U.S., both AWEA and WECC have activities aimed at producing a specification suitable for U.S. applications.

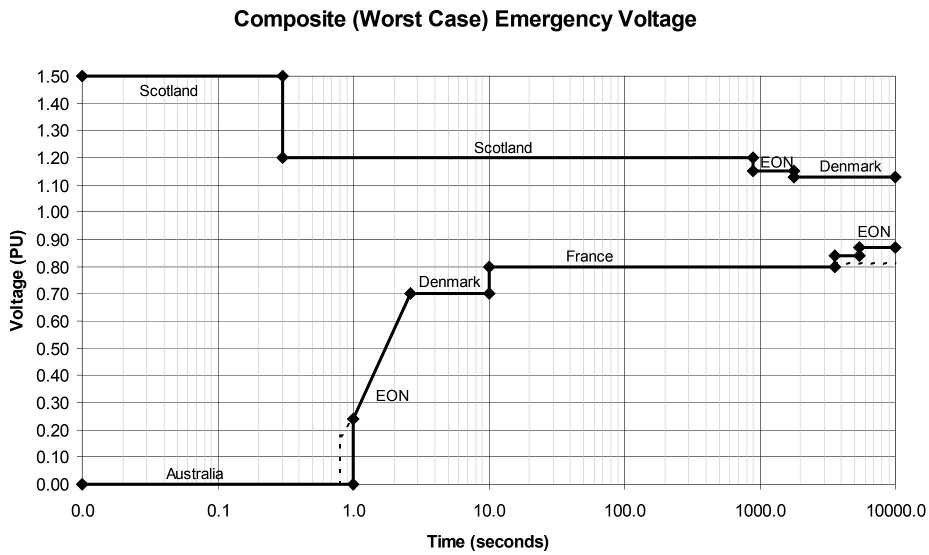

Figure 3.4 Composite of 50 Hz world LVRT specifications

The bottom-line is that the wind industry is moving towards LVRT being a standard requirement. New York State should adopt this approach as well for future wind development, removing this as a system concern.

3.2.1.4 Active Power Control

Wind generation has evolved with the primary objective of maximizing the energy production of each WTG, subject to the availability of wind. Philosophically and operationally, this is akin to other non-dispatchable resources such as run-of-river hydro, photovoltaics, and thermal co-generation where electricity production is secondary to the served process. Whenever the resource is connected, the active power is set by other considerations, such as water flow, sunlight, heat requirements, etc.

Most new wind farms connected at transmission voltage have provision for an external command (e.g., from the system operator, to disconnect the entire farm). Small or single WTG installations connected at distribution level may not have this capability. Beyond a trip signal, the vast majority of operating wind farms have no ability to modify their active power output in response to external AC system conditions or commands.

The next level of sophistication, which is now being built into some wind farms, is frequently termed "curtailment." This feature allows for the total output of wind farm to be limited by disconnecting some of the individual WTGs within a farm. This feature has been essential for the operation of some of the wind farms in Western Texas. The rapid addition of wind farms there, especially in the McCamey area, exceeded the local transmission capacity. So operations have been extensively curtailed there. A major, three stage, transmission reinforcement program is underway in Texas to relieve these and other constraints, and so the wind curtailments are not expected to continue in the future.

Curtailment is a relatively slow, open loop type of control that can be applied to all types of WTGs. With the continued growth of wind generation as a substantial source, several European systems are moving in a direction of requiring active, fast and automated participation in frequency and flow regulation by wind generators.

Most large (MW class) WTGs being manufactured today control the blade pitch of the turbine. The pitch is the angle of each blade with respect to the rotating hub of the turbine. Each individual blade pitch is adjusted by dedicated motor in the hub. The pitch is varied to control the amount of torque the wind produces on the generator drive train. When the wind is light to moderate speed (typically in the range of about 7 mph to 25 mph) the turbine will adjust blade pitch to generate as much power as the wind allows. From conventional generation perspective, the fuel flow is full on. For stronger winds up to maximum (typically in the range of 25 to 55 mph) the turbine will adjust the blade pitch to maintain rated electrical power output – spilling the excess wind energy. Above maximum wind speed, the WTG will stop producing electricity and assume a self-protective stance (blades pitched out and stopped, brakes on) until the extreme wind subsides.

It is clear that with suitable controls, the blade pitch control could be instructed to nmore wind that it would otherwise, reducing the electrical power output of the WTG. Regulating down is conceptually and technically straightforward. Regulating to increase power output is considerably more challenging. The WTG, unlike resources with controllable fuel supplies, cannot increase the wind speed. Thus, in order to be able to increase output in response to a command, the WTG must keep some capability in reserve – that is, it must spill wind that would normally produce power, so that it can be accessed when needed. Such commands could be either local or remote, and could be in response to frequency change (i.e., governor function), line flows (e.g., tie-line control) or both (e.g., AGC response).

Control of active power is receiving considerable attention in the industry. Both controls and equipment are evolving rapidly to be substantially more grid friendly. Providing active power control functionality does not necessarily mean using it all the time. These advances particularly help relieve concerns about "unwanted" generation under light load and high wind conditions. The most dramatic advances so far have been lead by Eltra, and are discussed below in Section 3.3.2 on system operations.

3.2.2 Bulk System Studies

3.2.2.1 Wind Turbine-Generator and Wind Farm Modeling

System planning studies are regularly performed by transmission system operators and by individual transmission owners. These studies are typically aimed at determining specific performance aspects of the bulk power system. The studies may be aimed at determining the impact of a specific project (e.g., generation addition) on the system, or at broader system issues, such as power transfer capabilities. These system studies are based on computer simulations that commonly include representation of very large geographic areas, with major transmission and generation components individually modeled within the system representation. All of the example systems perform such studies. The power industry has developed a suite of relatively standardized models for common components in the power system, including most types of conventional thermal and hydro generation.

System planning studies involving wind generation have, until recently, presented a significant problem to system planners because of a lack of adequately accurate, standardized models for individual WTGs and wind farms. When the wind penetration is small, simplifying assumptions for the wind generation is acceptable. However, as the penetration increases better models are needed.

Recently, the industry has moved to remedy the lack of good models. There has been quite a bit of modeling activity in Europe, but to a significant extent, the software packages used there are different from those used in the U.S. In the U.S., ERCOT has been working towards resolution of this issue. A large research and development project sponsored by ERCOT[x], and supported by a range of other interested participants, has been underway for more than a year. Utilities and manufacturers, most notably PacifiCorp and GE, have sponsored other development work. As the companion "Technical Characteristics" document reports, the result is that good models of all the different classes of WTGs are now available for the major simulation software packages used by U.S. utilities – PSS/e and PSLF.

Since the actual wind generation equipment is evolving quite rapidly, especially in the area of grid friendly functionality, these models are necessarily a work in progress. The models and available software is expected to continue evolving for many years.

3.2.2.2 Static and Dynamic Performance Evaluation

For the various types of studies mentioned above, each system typically has a set of system events, such as faults and equipment outages that are studied. These cases are typically run in accordance with a rigidly defined set of procedures and are subject to specific criteria that dictate acceptable performance. The example utilities and most others, appear to hold wind farms to the same standards for performance required for other proposed generators.

For static (load flow) analysis, proper modeling of the reactive power or power factor range of the wind farm is important. Most static analysis for system impact studies is performed at rated farm active power output, as this is usually the limiting condition for both thermal and voltage constraints. As noted above, properly designed and integrated wind projects can be designed to provide voltage regulation and a range of reactive power output, if so required.

For dynamic (stability) analysis, standard system fault cases (both normal and extreme contingencies) can be examined, as would be the case for other generation. The transient and dynamic stability of wind farms is generally superior to conventional generation. In the case of vector controlled type WTGs, it is essentially impossible for the machines to exhibit first swing (transient) instability. In this regard, transient stability analysis of wind farms can be quite uninteresting. However, incremental power transfer resulting from added generation (of any type) can create stability problems, and must be examined. One very important consideration for stability analysis of wind farms is to examine the vulnerability of the farm to tripping due to low voltages. The LVRT characteristics of the WTGs in a farm, as discussed in Section 3.2.1.3, will tend to dominate performance evaluations.

A separate dynamic performance aspect of wind generation that is not normally considered in the integration of conventional resources is voltage flicker. Flicker problems tend to be very localized, so this subject is discussed in Section 3.2.3.3 on local grid design issues.

3.2.2.3 Capacity Planning

Capacity planning including wind generation is the subject of considerable discussion within the industry. No obvious consensus has emerged. The issue is made relatively complex by the variability of wind. Most on-shore wind sites are generally considered viable, from a wind potential perspective, when the total expected annual energy production is above a 30% capacity factor. In this usage, the capacity factor is the ratio of total annual energy production divided by the total that would be produced if the farm operated at its rated power output 100% of the time (i.e., 8,760 hours). The energy production is also quantified by the hours of effective full load power (EFLP) output. EFLP is the equivalent number of hours at full output required to reach the total annual energy production. Thus, a 30% capacity factor corresponds to an EFLP of 2,628MWhr/year per MW of installed WTGs.

Wind generators also use a measure called availability. Availability for wind generation corresponds to the fraction of power that could theoretically have been generated considering all externalities compared to that actually generated. The externalities are mainly how much the wind blew, but can include other influences as well, such as transmission curtailments. Obviously 100% availability does not correspond to 100% EFLP. Availability of wind generation equipment has been steadily improving, especially in recent years. Availability levels above 90% or even into the high nineties can be found in recent installations. This is a major improvement over wind generation equipment that was being built a decade ago.

Within the U.S., there appear to be two major schools of thought regarding planning for (accounting for) capacity from wind generation. The first camp gives capacity credit for the annual capacity factor. For example, PJM[xi] uses annual capacity factor to give capacity credit. PJM gives capacity credit equal to 20% of the installed wind farm rating, until operation of the farm can document actual operation at a (presumably) higher capacity. The second camp considers capacity on the basis of expected power production at peak load – the condition which dictates overall system capacity requirements. Since expected power production at peak load may be significantly different (usually lower) than the annual average, capacity credit determined this way will be quite different.

European practice on capacity is somewhat different than U.S. practice. Note, for example from Figure 3.1, that Germany appears to have about 50% capacity reserve. At this preliminary stage, we have no data on how the European systems have handled this question.

3.2.3 Local Grid Design Issues

Beyond the bulk power system planning issues discussed above, integration of wind generation may significantly impact the transmission system in the immediate vicinity of the POI. This section briefly examines a range of localized system engineering issues that need to be addressed during the planning process. In some cases, these issues can impact the ability of specific projects to meet system performance requirements.

The choice of WTG technology has a major impact on most of the local issues addressed in this section. This is noted, where necessary. The companion technical characteristics document provides more detail of the specifics of each class of WTG technology.

3.2.3.1 Protection and Control

Wind farms and individual WTGs deliver short circuit current to the host grid during faults, in a fashion that is qualitatively similar to other conventional generation. Quantitatively, the behavior is different from conventional generation and between different types of WTG technologies. For this discussion, the key distinction is that fault current tends to decrease more rapidly (either by decay or by control) in WTGs than it does in conventional synchronous machines. At the system level, the most important practical implication is that, when new wind generation is added to an existing transmission system, the incremental increase in interrupting duty on existing switchgear and circuit breakers will tend to be somewhat less than would be the observed for addition of similarly rated conventional generators. The impact on momentary (close and latch) short circuit duty is comparable to that of a conventional generator.

Other system protection and control functions, such a line relaying, must be reviewed, as would be the case with any new generation. Vector-control type WTGs deliver controlled current during most faults. This further reduces the stress on system components, but may add complication to protective relaying coordination.

3.2.3.2 Isolation and Islanding

The discussion on low voltage ride through in Section 3.2.1.3 included some historical perspective on islanding. In general, the continued operation of pieces of the power system in unsanctioned and inadvertent electrical islands must be avoided. This is a concern with all types of generation. It is particularly of concern for generation that is embedded in the distribution system with loads. The newly approved IEEE Standard 1547-2003 (*IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems*) specifically addresses this concern, and sets guidelines for forced tripping of distributed resources. These so-called anti-islanding guidelines apply to all distributed generation resources, including wind with an aggregate capacity of 10MW or less and interconnected at primary or secondary distribution voltages. For most embedded applications, WTGs are considered to satisfy anti-islanding requirements without special controls or protection beyond typical over- and under-frequency and voltage relaying. However, more stringent scrutiny of this issue is continuing for all forms of distributed generation. In the future, additional anti-islanding protection and control maybe required for distributed wind applications.

The distinction between distributed wind generation, embedded in distribution systems and wind farms is crucial for this discussion. Wind farms connect at transmission voltages. To the grid, each wind farm acts like a conventional generator with rating of the entire farm to the extent practical. As the LVRT discussion points out, it is beneficial to system reliability if the wind farms continue operating through system disturbances. This requirement is almost diametrically opposed to anti-islanding requirements. Thus, a reasonable approach is for wind farms to have LVRT, and for WTGs embedded in distribution systems to have tripping functions to avoid islands. If distributed wind generation were to heavily proliferate, such that the combined capacity in a region becomes a significant source of generation, the tripping functionality to avoid local islands could have a reliability impact on the larger system. In this case, LVRT functionality requirements may need to be extended to the distributed WTGs, with some other means (e.g., direct transfer tripping, etc.) employed to prevent islanding.

Of the three WTG technologies, only vector-controlled machines theoretically have the capability to deliberately maintain sustained operation in an island without other synchronous generators. Providing such deliberate islanding functionality may have system reliability benefits, and is of particular interest during emergencies, as discussed further below.

Inadvertent islanding can also be a consideration for wind farms interconnected at the transmission level. Because transmission systems are typically networked, islanding is much less likely to occur than in radially configured distribution systems. Transmission islanding of a significant wind farm could result from a multiple contingency event or system breakup. The significant difference between islanding of a wind farm and islanding a conventional power plant is that the islanded wind farm may provide significantly less control of voltage and frequency in the island. Such an island is unlikely to persist, but uncontrolled voltages in a briefly sustained island could be damaging. This is of particular concern when stall-regulated and scalar-controlled WTGs are islanded with a significant shunt capacitance (shunt capacitor bank, cable, or long overhead line), and self-excitation occurs. Such an event resulted in damaging overvoltages in an early wind farm.

In general, system needs for integration of individual or very small groups of WTGs embedded in distribution systems can be different from larger farms coneected at transmission voltages. NYS should adopt application policy that allows for slectively waiving or odifying interconnection requirements for small facilities (e.g. less than 5 or 10 MW).

3.2.3.3 Flicker

The variability of power output from individual WTGs and wind farms has the potential to cause voltage flicker. Flicker, as the name suggests, is the variation of visible light from light sources, especially incandescent lamps, whose output is sensitive to voltage. The human eye is quite sensitive to variations in light intensity. There are many types of industrial and power system equipment that can cause flicker, and there is a significant body of engineering experience and practice to address the problem.

From the perspective of integrating new wind generation resources, there are several key flicker-related observations:

1. System impact studies do not normally consider flicker, with the exception of calculation of maximum voltage change for some types of switching operations (e.g., capacitor switching)
2. Flicker concerns are greater for weaker systems. Weakness is relative – the best measure of weakness is (probably) short-circuit ratio: the ratio of the system short circuit MVA at the POI divided by the total MVA of WTGs in a farm.
3. For a given short-circuit ratio, single WTGs or wind farms with a small numbers of WTGs present a higher risk of flicker problems. (due to higher granularity or less diversity, take your pick)

4. There are no uniformly accepted practices for analyzing flicker from wind resources. In the U.S., IEEE Standard 519-1992[xii] dictates acceptable flicker levels. In Europe, IEC Standard 61000-4 (double check number, give reference) applies. IEEE 519 targets regular, periodic voltage disturbances and is rather ambiguous for aperiodic disturbances characteristic of wind.
5. The choice of WTG technology makes a significant impact on the flicker behavior of a farm – both in terms of whether a problem will be likely, as well as the type, cost and efficacy of mitigation, if there is a problem. Certain WTG designs, typically scalar-controlled or stall-regulated, have considerable current inrush when initially energized. This can cause a abrupt voltage deviation which is often called flicker, even though it does not occur repeatedly.
6. All other aspects being equal, vector-controlled WTGs have better flicker characteristics than scalar-controlled WTGs, which in turn have better characteristics than stall regulated machines.
7. Flicker problems can be solved, but the solutions can be costly.

3.2.3.4 Local Stability Issues

There is some potential for interaction between WTGs within a farm. There is also some potential for interaction between the supervisory controls of nearby wind farms. These problems can be addressed by suitable control modifications. Concerns about the potential for local mode oscillations, between WTGs within a farm or between nearby farms have been raised, however, this preliminary investigation has not found any evidence of such problems occurring in the field.

3.2.3.5 System Restoration

In modern wind farms, individual WTGs will normally resume operation when wind and terminal conditions allow. This automatic restart of WTGs can be blocked by the farm (or in some cases, the system) operator. These restart characteristics are generally desirable for system restoration. Restoration planning should take this into account.

Blackstart is a technically more difficult issue. In order to achieve blackstart, a generating facility must be able to (a) supply the necessary power to all of its own auxiliary and safety equipment, (b) establish and regulate system frequency (to 60 Hz), and (c) establish and regulate voltage. In short, blackstart requires the creation of viable electrical island. Of the three WTG technologies, only vector-controlled machines have the theoretical capability to function in an island. A blackstart island *might* however have different characteristics if it included other generation resources.

For this preliminary report, there is no information that indicates that there is significant use or dependence on wind generation for blackstart in any major power systems.

The technology trend for WTGs and wind farms is towards functional capability that could be adapted to support system blackstart needs. Further development of equipment, control and application practice is needed for future applications.

3.3 OPERATIONS

3.3.1 Variability of Wind Power: Statistical Perspectives

Variability of wind is the primary differentiation between wind generation and other resources, especially for operations. In this subsection, variability from the narrow perspective of expected power production by wind resources will be examined. The discussion is divided into two time scales of variability: seconds to hours, and diurnal to seasonal. In the following subsections, the implications of this variability on system operations are reviewed.

3.3.1.1 Seconds to Hours

Table 3.2 was derived from NREL work[xiii] which distilled more than a year of high-resolution measurements from two wind farms in Minnesota, each of approximately 100MW total installed rating. The table shows the expected statistical variation in wind farm power output in different time frames. This provides a benchmark reference for the expected level of aggregate power fluctuation from a wind farm of this size (~100MW).

Table 3.2. Anticipated Power Fluctuations due to Wind Variability on a Farm Basis

Time Unit	Range of 1σ
1 second	0.1-0.2 %
1 minute	0.5-1%
1 hour	7-11%

The fastest time frame is second-to-second variation. The variation over the farm is relatively small; one standard deviation[2], σ, is in the range 0.1 to 0.2% of the total farm power output. This is mainly due to the physical spacing between the wind turbines, which tends to smooth out these higher frequency wind, and therefore power, variations across the farm. The degree to which

[2] A standard deviation, σ, is a statistical measure of the expected departure from an average value. In a normal distribution 63% of samples fall within ±1σ of the average.

wind fluctuations simultaneously appear on one source compared to another is the statistical correlation. In the limit, if all wind fluctuations always appear at exactly the same moment on two sources, the correlation is perfect or unity. It is possible to examine the correlation between individual WTGs in a wind farm, or the correlation between output of entirely separate wind farms. At the wind farm level, increasing the physical spacing between individual turbines reduces the correlation, with the result that the net statistical variability of the farm is quite low compared to that of an individual WTG. The variability drops with more turbines.

In the next slower time frame, minute-to-minute, the expected variation is larger, because these slower variations in wind speed tend to affect a larger area, and therefore more machines, simultaneously. There is some level of correlation observed across the farm. The slowest time frame, hour-to-hour, is primarily dictated by larger weather patterns, and tends to affect the entire wind farm; i.e., the correlation between individual WTGs within a farm is high.

When a power system has multiple farms, especially ones that are separated by significant distances, the correlation between hourly variability of each farm drops. The NREL study considered two farms of similar size in the same region, but separated by about 125 miles. The correlation between the farms in the shorter time frames was small. In the hour-to-hour time frame there was only partial correlation. This indicates that individual wind farms in the same region will exhibit total less hour-to-hour fluctuation than is shown in Table 3.2. The NREL German study[xiv] presents a range of time-separation correlations. That study found that 1 hour correlation for farms separated by more than 50 miles (80km) were relatively low.

3.3.1.2 Diurnal and Seasonal Variability

There are meteorological and topological factors that dictate general trends in wind for specific areas and regions. These factors provide the backbone for the sophisticated techniques used by developers and wind prospectors to search for good sites. These longer-term variations present both operational and planning challenges. Diurnal (daily) and seasonal variability in wind will drive both planning and operational practices on a regional basis (e.g., state, European country, ISO)

Daily load and wind generation profiles are shown in Figure 3.5 (courtesy of Henry Durrwachter, TXU). The load profile is the hourly averages for the month of August for TXU Energy in Texas. The wind generation profile is the August hourly average power for the 34.3MW Big Sky wind farm in the TXU system. For this particular system, the diurnal load and wind production patterns are significantly out of synchronism, with the wind production reaching a maximum between 2 and 3 AM, and the system load reaching a peak between 4 and 5 in the afternoon. This effect was discussed in Section 1.2.2 on Capacity Planning; for TXU result is a 10.9% capacity factor at peak load. Such profiles are system specific, however it is not unusual for load and wind generation profiles in summer peaking U.S. systems to exhibit this general pattern.

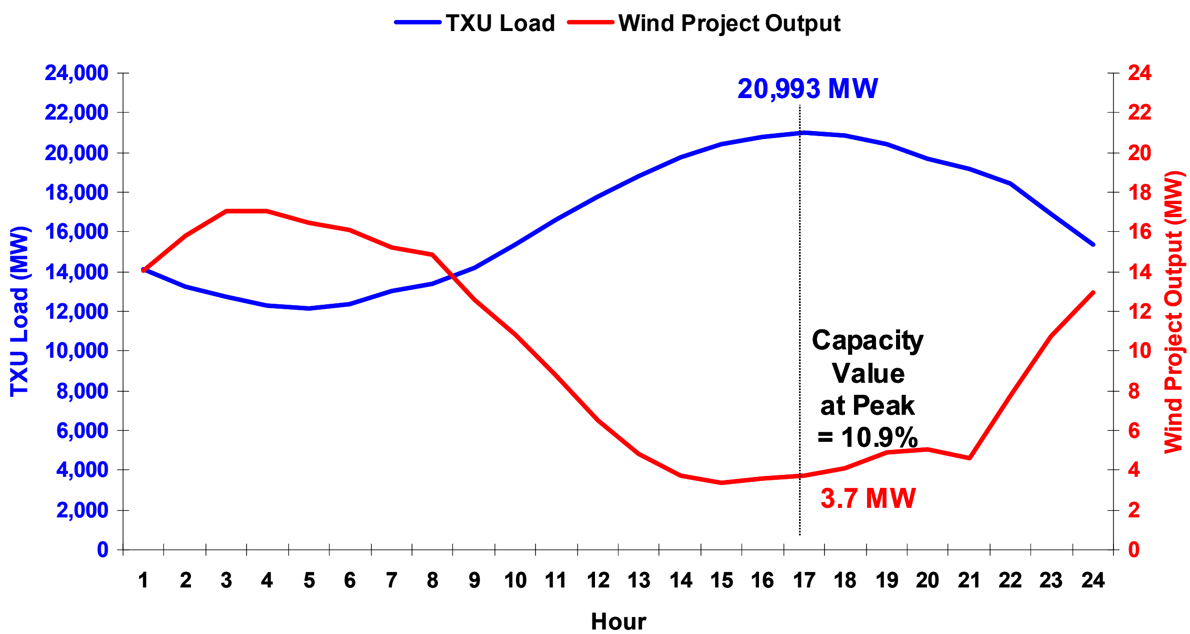

Figure 3.5 TXU Diurnal Pattern[xv]

Seasonal trends are also important for planning and operations. A seasonal projection and actual performance for the same 34.3MW TXU Energy wind project is shown in Figure 3.6. The deviations from forecast are primarily a consequence of unfavorable weather conditions and equipment availability. There is very little impact from curtailments, since this particular project is located downstream of most of the system transmission constraints that have caused curtailments on other wind projects in western Texas (as discussed in Section 3.2.1.4).

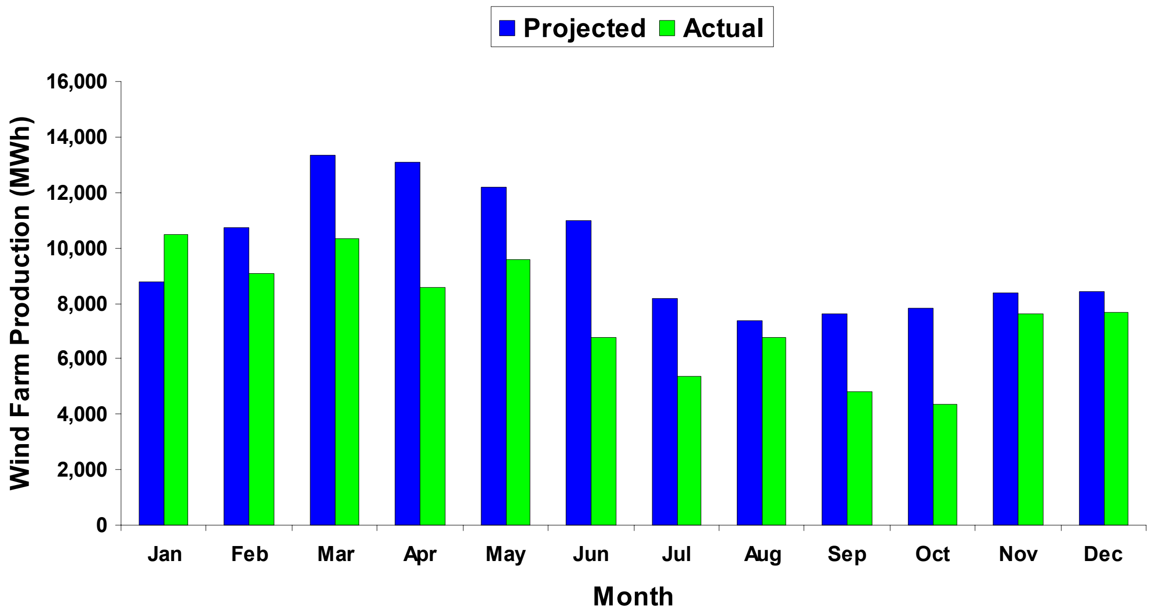

Figure 3.6 A TXU Energy Wind Project Seasonal Pattern: Forecast and Actual

Each system will exhibit diurnal and seasonal patterns specific to that system. The Minnesota (NSP) projects exhibit diurnal patterns with less peak to minimum variation than the TXU example. For those projects, the seasonal variation is also slightly less pronounced.

A final aspect of interest is annual growth of installed wind generation. The ERCOT experience with the renewable portfolio standard was a surprise to some: The RPS targeted 2000 MW of wind generation by 2009. ERCOT hit about 1900 MW in 2003.

3.3.2 New York State Wind Power and Load Variability

The expected variability of wind power in New York State will depend on the number and location of sites that are developed within the state. The wind data on the 101 prospective new wind sites developed by AWS provides insight into the hourly variability that would be expected in the limiting case with all the candidate sites developed.

The figures and tables presented in this section are based on a statistical analysis of the total hourly output of all 101 sites, developed to their maximum capacity of 10,026MW. The New York State hourly load data presented is from the GE MARS database discussed in the Reliability Analysis in Section **0** of this report. The wind data presented in the figures is for 23 hours per day, as data discontinuities at midnight have been removed[3]. Table 3.3 lists three data series, which are plotted in the figures. The first series, titled "Wind Delta," is the annual distribution of hour-to-hour variation in wind production for the entire state. The statistical bins are each 100MW. That is, all variations within ±50MW of the bin label count as one occurrence for that histogram bar. The second series, titled "Load Delta," is the annual distribution of hour-to-hour variation in system load for the entire state. The third series, titled "Load-Wind Delta," is the combined effect of wind and load variation. Table 3.4 presents all the statistical data for the three series.

Figure 3.7 shows the distribution of hour-to-hour variation in wind production. Since the total installed base for this base is 10,026MW, each 100MW statistical bin represents a change of almost exactly one percent. The standard deviation of this distribution, from Table 3.3, is 467MW or about 5% of the 10,026MW of installed wind generation. On a percentage of installed wind generation, this is about half the level of variability of a single farm listed above in Table 3.2. This reflects the spatial diversity of multiple sites.

For comparison, the hour-to-hour variability of the total New York Control area load is shown in Figure 3.8. The distribution is somewhat less normal than the wind profile, and has a standard deviation of 920MW, slightly less than 3% of the peak load.

As noted in the previous section, the variation in wind generation and system load may increase or decrease the total system variation. Figure 3.9 shows the combined impact of load and wind variability for the year. The two series are combined chronologically so that the wind behaves as a load modifier. Thus, the variations appear as net load variation. The overall impact of the 10,026MW of wind generation on the system is small, but not insignificant. The number of hours during which essentially no change in load occurs, i.e., the peak at the center of the distribution, is reduced. Possibly more important, there are more samples at the extremes. The standard deviation (from Table 3.4) of this combined profile is 1,086MW, which represents an 18% increase over the 920MW standard deviation of the load variability alone. As the last row of Table 3.3 shows, there are 27 hours for which the net change in load plus wind is greater than 3,000MW. The single largest hourly increase in net load changed from 2,805MW without wind to 3,609MW with wind. This is shown in the row labeled "maximum" in Table 3.3. The single

[3] The AWS data was developed for individual days, consequently the change in power at midnight is physically meaningless, and is removed from the plots.

largest decrease in load changed from 2,903MW without wind to 3,682MW with wind. This is shown in the row labeled “minimum” in Table 3.4.

This impact of wind generation on the net or apparent load variability will obviously be lower for a smaller level of wind penetration. The relationship is not linear, but a linear approximation could be used as a conservative estimate. The 18% increase in variability for 10,026MW of wind generation corresponds to a rate of 1.8%/1,000MW of wind generation addition. Thus, for example, the addition of 3,300MW of wind generation to bring the state to a 10% level of penetration, would result in an approximately 6% increase in net load variability (from 920MW to 975MW).

This preliminary analysis provides insight into the expected level hour-to-hour variability that might accompany large amounts of wind generation in the state. It does not provide the detail necessary to make an assessment of the expected impact on hourly and daily operations. In Phase 2, the variability of selected sites will be investigated further, including consideration of intrahour, diurnal, monthly and seasonal impacts.

Table 3.3. New York State Wind and Load Variability Data

Number of Occurrances

Bin (MW change)	*Wind Delta*	*Load Delta*	*Load - Wind Delta*
-3000	3	0	11
-2900	0	1	8
-2800	1	0	3
-2700	2	0	9
-2600	3	1	9
-2500	2	2	12
-2400	3	6	14
-2300	2	8	28
-2200	3	14	33
-2100	11	23	51
-2000	6	20	56
-1900	7	53	85
-1800	5	106	91
-1700	10	99	71
-1600	8	85	108
-1500	13	61	98
-1400	16	59	108
-1300	19	81	132
-1200	24	118	136
-1100	27	108	163
-1000	53	135	169
-900	66	161	166
-800	72	178	187
-700	114	250	222
-600	176	245	241
-500	222	202	227
-400	313	294	272
-300	447	317	283
-200	582	422	315
-100	855	610	334
0	1255	639	373
100	1308	447	385
200	785	480	335
300	574	396	298
400	365	264	326
500	260	254	267
600	192	200	246
700	126	178	244
800	108	199	242
900	80	182	183
1000	55	177	207
1100	41	195	170
1200	53	170	187
1300	27	118	131
1400	27	79	136
1500	7	87	118
1600	17	77	114
1700	12	75	89
1800	12	65	105
1900	5	68	75
2000	7	83	77
2100	6	61	70
2200	1	46	68
2300	2	53	59
2400	1	37	48
2500	2	52	49
2600	1	27	42
2700	0	18	35
2800	0	8	19
2900	1	1	16
3000	0	0	12
>3000	0	0	27

Table 3.4. New York State Wind and Load Variability Statistics

	Load Delta	*Wind Delta*	*Load - Wind Delta*
Mean	58.06	-16.32	74.38
Standard Error	9.83	4.99	11.60
Median	0.00	0.00	0.45
Mode	0.00	0.00	0.00
Standard Deviation	919.99	467.08	1085.90
Sample Variance	846,373	218,162	1,179,185
Kurtosis	0.37	5.74	0.05
Skewness	0.25	-0.27	0.11
Range	5,708	6,361	7,291
Minimum	-2,903	-3,529	-3,682
Maximum	2,805	2,832	3,609
Sum	508,584	-142,965	651,549
Count	8,760	8,760	8,760
Largest(1)	2,805	2,832	3,609
Smallest(1)	-2,903	-3,529	-3,682
Confidence Level(95.0%)	19.27	9.78	22.74

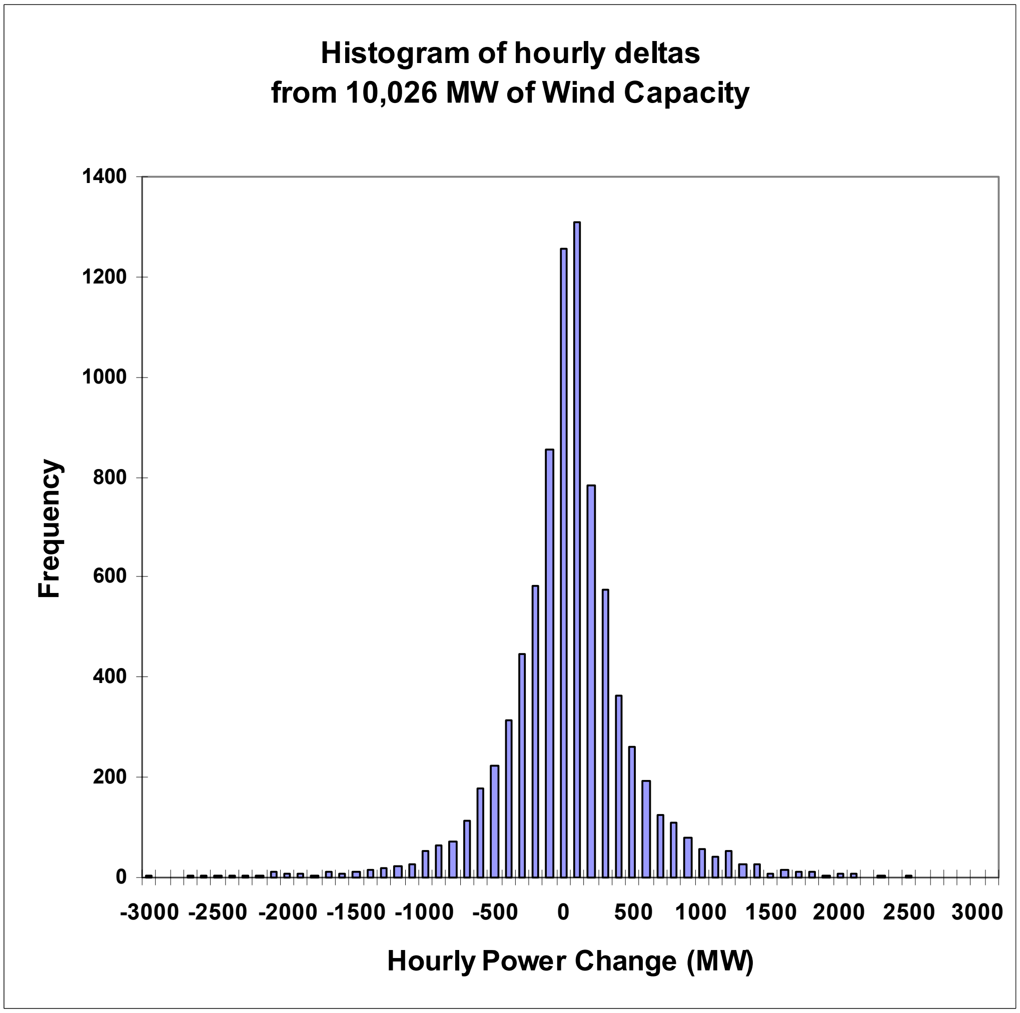

Figure 3.7 New York State Wind Variability for All Candidate Sites

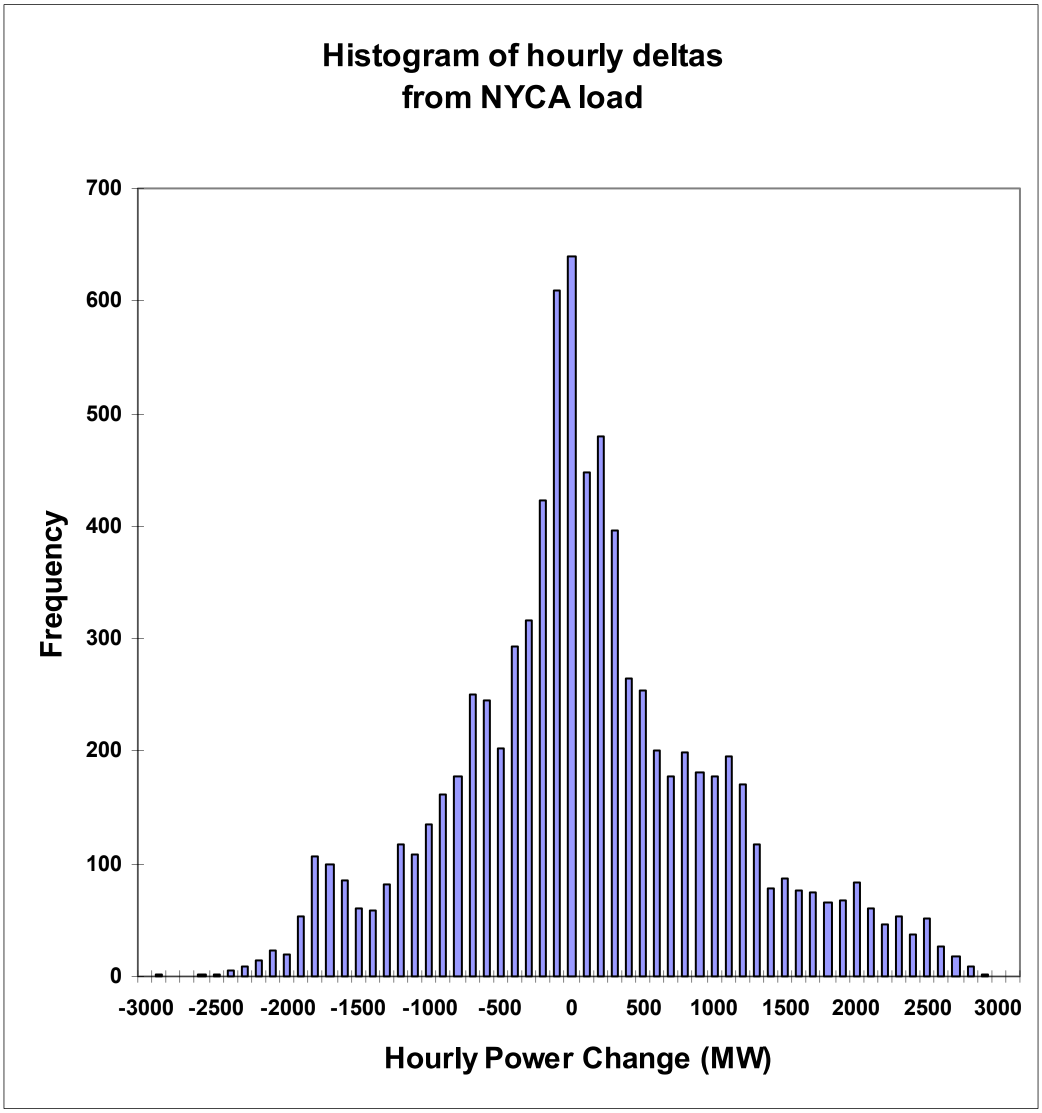

Figure 3.8 New York State Load Variability

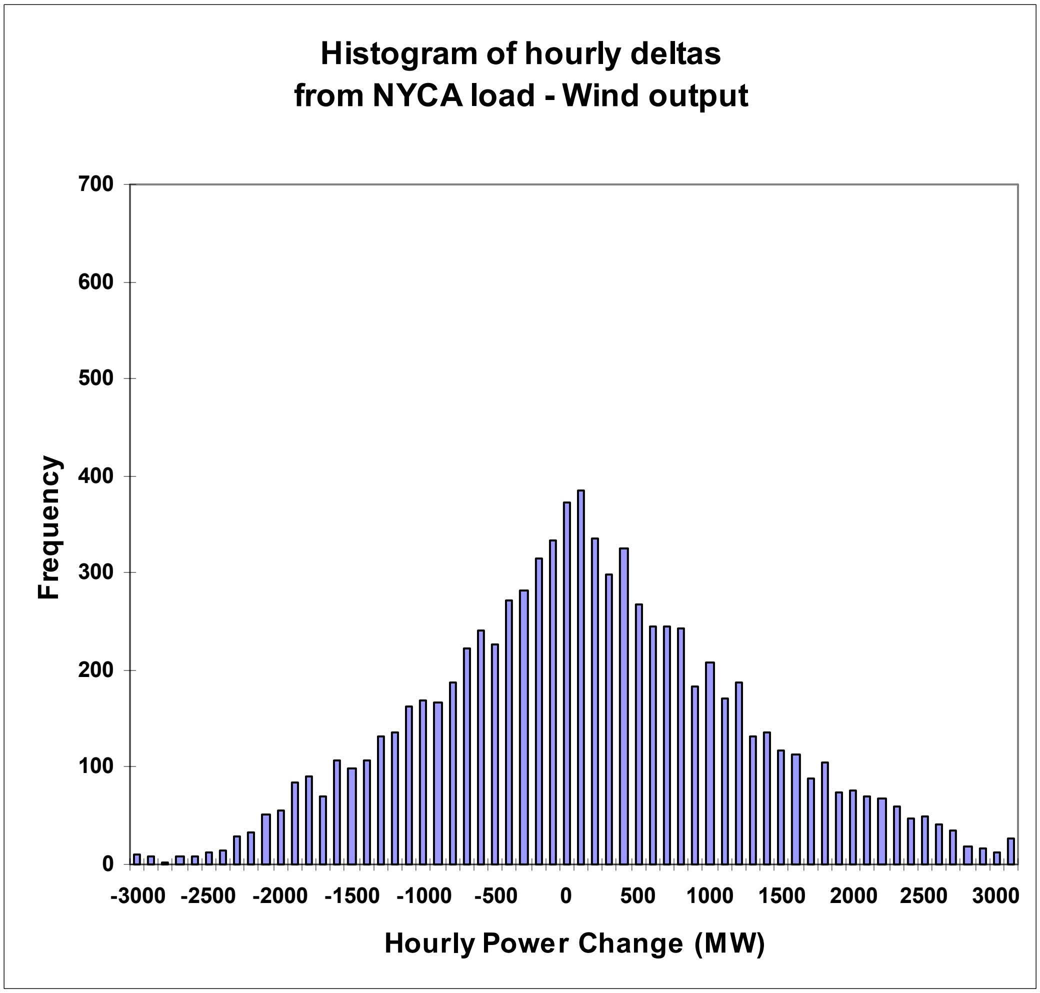

Figure 3.9 New York State Combined Load plus Wind Power Variability

3.3.3 Active Power Impacts and Control

There are operation implications and responses to the variability in power production introduced in the previous subsection. These variations in MW output impact both the performance and the security of the power system. Therefore, the entire bulk power system, including other generation resources, transmission and controls, must be positioned to respond to these variations. The primary system response will be for the active power from other generation facilities to vary in opposition to wind generation variations. This active power response of the system is examined in this section. There is a secondary impact on voltage and reactive power, which is examined below in Section 3.3.3.

The different time scales of variation outlined in Table 3.2 correspond roughly to different categories of system response. The PacifiCorp/NREL[xvi] study on cost of wind integration makes a distinction between three categories of system response, which overlay roughly with the table, as follows:

1. Seconds to minutes: “regulation” – AGC (and governor) response.
2. Minutes to hours: “load following” – ramping generation output up and down.
3. Hours to days: “unit commitment” – daily scheduling to meet reliability requirements.

Each of these time frames is examined below.

3.3.3.1 Regulation

The system operator has an obligation to maintain system frequency and intertie power flows within relatively tight constraints. The normal second-to-second variation in system load causes the system frequency and flows on ties lines to drift outside of their targeted range. The first line of defense against frequency deviations is the governors on some turbine-generators within the system. These are local, autonomous controls, over which the system operator has little or no control. Governors do not respond to variations in tie line flows. WTGs do not presently provide governor response. At the system level, the fastest acting control is the Area Generation Control (AGC). This automatic centralized controller monitors error in frequency and tie line flows, and periodically sends signals to a select group of turbine-generators to raise or lower their output to correct the detected error. These selected turbine-generators provide regulation as an ancillary service to the system. The AGC signals are typically broadcast every 2 to 5 seconds. When the system load is changing rapidly, the turbine-generators responding to the AGC signals must vary their output faster and over a wider range, or alternatively more turbine-generators must be recruited to provide this function, thereby spreading the regulation burden among more machines.

From the perspective of AGC, wind generation effectively adds to the volatility of load fluctuations. However, the level of volatility or uncertainty is higher with wind generation than with loads. As Table 3.2 indicates, the second-to-second fluctuation from a single large wind farm will tend to be relatively small. They will also tend to have no correlation with load variations in the same time frame. Thus, they may or may not add to the level of control action required. At modest levels of penetration, the impact is insignificant. The UWIG study[v] found this impact to be small enough to have no cost impacts. At moderate levels of penetration, additional regulating resources may need to be committed to provide this service. It is possible that high levels of penetration could influence the type of resource committed (i.e., resources better suited to meeting the required amplitudes and rate of power variation). This preliminary investigation has uncovered no evidence that any of the U.S. systems have encountered or quantified additional resource requirements for regulation. This is expected to be true for NYS as well. This will be explored further in Phase 2

Potential advances in WTG and wind farm supervisory control technology discussed in Section 3.2.1.4 offer substantial benefits for regulation. The wind industry is beginning to develop new concepts for smoothing output and providing grid friendly dynamic response. These concepts hold promise for dynamic performance that may be superior to that presently achieved by conventional generation resources. This will be explored further in Phase 2.

3.3.3.2 Load Following

During normal operations, the daily load profile, which tends to be dominated by the diurnal cycles of the system, is primarily accounted for in the day-ahead unit commitment. Within each individual hour, the minute-to-minute variations in the load, both projected (forecasted) and unplanned (deviations from forecast), are made up by load-following generation. Again, generators participating in load following will be periodically instructed to increase or decrease their output in accordance with the system need and a determination of the most economic resources to provide the needed power. This is normally termed economic dispatch, and typically occurs at five-minute intervals.

The minute-to-minute fluctuation due to wind, again as suggested by Table 3.2, is statistically moderate, with a standard deviation of 1MW/min for each 100MW of installed wind farm capacity at a single site. This level of variability does not appear to present much of challenge to a large system. However, it is important to recognize that such minute-to-minute changes will, at times, be serial and of the same size. Thus, while 1% change over one minute might not present a challenge, 15 or 30 minutes of sustained change can result in a significant change of power in the load following generation. As the profile in Figure 3.5 shows, it is not only possible, but may in some applications be typical, for the wind power to be decreasing while load is increasing, and vise versa. The combined impact of load and wind variability will be to increase the amount of generation needed to follow load.

The New York State variability results presented in Section 3.3.2, while based on hour-to-hour variation,provide some insight on the expected impact of wind generation on load following. Those results showed increased net load variability due to wind generation. For each 1,000MW of added wind generation, the standard deviation of hour-to-hour net load variability increased by about 17MW from 920MW without any wind generation. The addition of 3,300MW (10% penetration) of wind generation would increase the load variability by about 6% or about 55MW. The impact on intrahour variability is expected to be higher. NYS presently procures load following service from participating generators. The increase in load variability due to wind generation is expected to impact the requirement for load following. In the PacifiCorp analysis, the load following reserves were increased by the percentage increase in the standard deviation of the load after the introduction of the wind generation, where wind was treated as a load modifier. On this basis, a 6% increase in load following reserves would be required to accommodate 3300 MW of wind generation.

This tendency for the rate of change of wind power and system load to have a negative correlation can influence both the amount and type of generation required to provide load following. In other words, the total variation and the rate of change at any interval will tend to be higher than without wind generation, requiring more control range and ramping capability. Selection of machines for load following considers control range, ramp rate capabilities, and cost of energy.

The PacifiCorp/NREL study [xvi] concluded that the load following burden was the most difficult and potentially costly aspect of system wide active power management due to wind. Furthermore, the study concluded that the cost of load following increased as wind penetration increased.

European experience seems to support this observation. The experience of Eltra in Denmark is of particular interest. Figure 3.2 shows that Eltra has an especially high penetration of wind generation. The figure shows that at peak load, it is possible for 60% of the required power to come from wind generation. Under light load conditions, the system can, and does occasionally, exceed 100% wind penetration. That is, the operating wind resources produce more power than the total system load. Under these conditions, Eltra exports the excess power to their neighbors. Providing load following and regulation under all operating conditions, but especially at light load, is difficult and expensive. They operate thermal units and depend on their tie lines to the neighboring systems to meet these demands.

The economic impact and the need to reduce their reliance on neighboring systems has driven Eltra to move towards some creative solutions. The new 180MW Horns Rev[xvii] offshore wind farm is equipped with several new wind farm level controls that are intended to provide operational flexibility and to mitigate the network operational difficulties associated with wind fluctuations. There are four control features provided, that are based on the fundamental equipment characteristics discussed above in Section 3.2.1.4. The features, which can be enabled and adjusted by the system operator, are:

1. Power Rate Limitation. This control limits the rate at which the total farm power can increase. Under conditions of rapid increase in wind speed, the rate at which farm output rises can be limited to a specified maximum ramp rate.
2. Absolute Power Constraint. The total power output of the farm can be limited to a level below the farm maximum. So, for example, a limit of 160MW would allow the farm output to vary in response to wind fluctuation anywhere between 0 and 160MW, but would prevent it from reaching the 180MW capability.
3. Delta Control. This control maintains a specified reserve for the total farm. For example, the system operator could instruct the farm to maintain total output at 20MW less than whatever output would normally be produced for the present wind. This reserve can then be called upon by the system operator for regulation purposes. (This reserve could also provide range to enable a local autonomous governor control; however, we believe that a governor feature is not presently included in the controls.) For this control to be effective, the wind must not drop below that required to maintain the specified reserve.
4. Balance Control. In this control mode, the total MW output of the farm is held constant at a specified value. For this control to be effective, the wind must not drop below that required to maintain the specified level.

It is important to note that using each of these features results in reduced energy production by the wind farm. The lost energy production is a function of control mode, available wind and operator specified set points. The four features are listed in order of increasing energy production penalty. From an economic perspective, the controls are spilling free fuel that cannot be recovered at a later time, and thus ought to be used only when necessary. Enabling these features must be balanced against the cost of obtaining these regulation and load following functions from other resources. At the system level, economic use of these features will tend to occur when the cost of regulation from other resources is relatively expensive compared to the marginal price of electricity, i.e., at light load.

Overall, active power management of wind generation is new ground. The industry, led by Eltra, is still learning. It is expected that with experience, both practice and control details will evolve rapidly.

3.3.3.3 Unit commitment

System operators rely on load forecasts, projections of transmission system conditions, and economic inputs from available generating resources to perform unit commitment. Unit commitment typically covers one to three days ahead, depending upon the system. The system operators issue an hourly schedule of generation resources needed to meet the anticipated loads and constraints, with a level of reserve necessary to satisfy the reliability criteria of the system.

Day ahead planning and unit commitment are impacted by the variability and uncertainty of wind. To some extent, the key issue is the confidence and fidelity of the short-term wind forecast. Systems operations normally considers the instantaneous loss of critical system elements. Most systems, including New York State, plan for the loss of the single largest generating resource and/or largest power infeed. Unlike these discrete steps in resource status, variations in wind power output from multiple WTGs while rapid at times, are not instantaneous. The unit commitment problem takes on a somewhat different aspect, blurring the line between load following and spinning reserve.

Experiences from the example systems illuminate the challenges and practices. More exact determination and discussion of each example system operating practice will be provided in Phase 2.

The Eltra system has very high levels of wind penetration. The Eltra report[xviii] states "wind is the decisive factor for *daily imbalances*." For their system, wind countered other imbalances about 20% of the time in 2002. Eltra commits large central station thermal generation to account for uncertainties in wind production. Their unit commitment is also significantly impacted by the risk of common-mode tripping, as discussed in detail in Section 3.2.1.3. Eltra does not commit units to meet all possible variations due to wind, and relies on their tielines to neighboring systems to meet occasional extreme variations. Eltra has stated that commitment of these large thermal units incurs significant operating costs

In Spain, discussions with grid operators suggest that their primary consideration regarding unit commitment is risk of common-mode tripping due to system faults, and is not driven by uncertainties in forecasted wind energy production. This anecdotal information will be examined further in Phase 2.

In Germany, the system operator has access to quite sophisticated wind production forecasting tools. ISET indicates[xix] that the operator takes these forecasts into account for unit commitment by treating the projected wind production as a (negative) load modifier with volatility. One experience in Germany is worthy of note. On one occasion[xx], under relatively load light conditions, weather conditions with high, sustained wind occurred over much of the northern part of the system. Schleswig-Holstein state, which borders Eltra to the north, reached a local wind power penetration in excess of 100%, and power was being exported to neighboring German states. Over a relatively short period of time, the wind in region rose to extreme (nominally a 500 year storm) levels, causing most of the wind generation to revert to their high wind defensive condition (i.e., they tripped off line). Thus, over a relatively short period of time, the state shifted from being a net exporter of power to substantial importing. The system tolerated this sequence of events. Since then, we believe that the German system operators adopt a defensive posture (more generation on-line) when the weather forecast includes the possibility of violently extreme wind. This is believed to be similar to the type of defensive strategy that New York State uses for other violent weather and solar-magnetic disturbance forecasts.

In Minnesota, Xcel North (NSP) performs three day ahead planning [vi], with 10 minute spinning and non-spinning reserve based on worst loss of source (similar to New York State). They use machines with fast load ramp rates (12-15MW/min) for their AGC. To account for the contribution of wind, those “responsible for generation scheduling” use seasonally adjusted capacity factors – with an average of 30% for the year, reaching a seasonal high of 40% in spring, and adjusted to a low of 15% for the summer. This is similar to the variations found in the New York State data and shown in Reliability Analysis Figure 5.7. The day-ahead operators use a discounted value of the forecast wind production for the next day. They vary the discount, based on their confidence in the forecast. They have less confidence when the forecast is for volatile wind conditions, and so increase the discount compared to forecasts of more steady weather. Quantitative information on the range of discount values was not obtained for this preliminary review.

The major wind farm in New Mexico has just entered commercial operation, and so PNM has little operating experience to report. This preliminary review has not ascertained if or how ERCOT has modified unit commitment practice to account for their wind generation.

The PacifiCorp/NREL[xiv] study of the cost impacts of operation with wind indicates that they believe that their tool is pessimistic with respect to the ability of their hydro resources to mitigate some of the cost impacts associated with wind uncertainty. They note, “At this early date, no major issues have surfaced with regard to system operations." This is an area that needs further investigation in Phase 2.

As noted above, day-ahead forecasting and the level hour-to-hour variability does not provide a complete picture of the potential impact on operations. Rapid and sustained drop of output over several minutes is of particular concern. The question arises, "could such a drop possibly impact the state's 10 minute operating reserves"? New York State determines the system 10 minute operating reserve requirement based on the single worst system contingency. At present, NYS maintains a minimum 10-minute operating reserve of about 1,200MW, of which at least half must be synchronized. Recognizing that 10 minute operating reserves are dedicated to preparing the system for major contingencies, it is nevertheless valuable to check whether there is significant risk that a rapid drop in total wind generation could have the appearance of a major contingency. One conservative check is to examine the total change in output over 10 minutes as though it were a single discrete contingency. System experience with wind farms shows that the possibility of reaching a 1200 MW change in 10 minutes is very small. Consider: The minute-to-minute fluctuation from a single wind farm, as given by one standard deviation, 1σ, is expected to be on the order of 1% (per Table 3.2). Using the 1% figure on a state-wide basis is conservative, since wind farm separation will significantly reduce this level in this time frame. Then, for NYS: (1) 1σ is 1% of 3300 MW, which equals 33 MW. (2) The probability of a single change $\geq 3\sigma$ is 0.0013; so only about 1 out each 1000 minutes of operation at full power would be expected to result in a change of 100 MW. (3) To reach a change of 1200 MW over a ten minute period, requires ten consecutive changes of 120 MW, and finally (4) the full 3300 MW will rarely be reached. Thus, variability of wind at this level of penetration is not expected to change the limiting contingency that determines the present 1200 MW 10 minute operating reserve for the state.

In summary, the example systems have successfully operated with wind generation, and have unit commitment and operating reserve practices that work. This is a critical issue for New York State, and this preliminary investigation has not clearly illuminated a preferred strategy for unit commitment with significant wind generation. Phase 2 will examine this issue in considerable detail.

3.3.3.4 Monitoring

One of the problems that some systems with many distribution connected WTGs (e.g., Eltra) face is that these embedded wind generators are not monitored in real-time. The system operators have not directly communicated information about the status and output of the generators. This lack of good information makes both the load following and unit commitment problem more difficult. New projects are generally required to have significant real-time monitoring that is accessible to the system operator.

3.3.4 Voltage and Reactive Power Management

Voltage regulation issues related to planning are discussed in Section 3.3. Two issues related to system operations are discussed here; one based on current practice and one based on emerging technology.

3.3.4.1 Power Factor vs. Voltage Control

The U.S. experience with wind farm integration has evolved towards a requirement for voltage control in many applications. In systems with multiple voltage control devices, coordination of the voltage regulating devices, including consideration of one or more wind farms can be challenging. In New Mexico, for example the Taiban Mesa farm is required to provide voltage regulation at the 345kV POI bus. The voltage controller was designed to work without dedicated communication to other voltage control devices existing on the transmission system: specifically an HVDC tie and a large bank of switched shunt reactors. To accomplish this coordination, the voltage regulator relies on a proportional controller. There is no integral control to avoid control conflicts, and the system operator can remotely adjust the setpoint to achieve the desired system voltage. A similar approach is used in a number of wind farms nearing commercial operation in Minnesota.

European practice with wind generation has generally imposed power factor control on wind generation, rather than voltage control. Europeans commonly require wind generation to be power factor neutral – that is, to operate at or near unity power factor. There are both systemic and historical reasons for this. Much of the wind generation in Europe is connected at distribution level, with single or very small groupings of machines. Active voltage regulation by resources embedded in distribution systems is relatively unusual, because it can create voltage and circulating reactive power flow problems. Even for wind generation connected at transmission voltages, power factor control has continued to be the standard in Europe. European grids are physically more compact, with higher short circuit levels and less severe reactive power management problems than are seen in more sparse U.S. grids. European practice is starting to include voltage regulation, especially in conjunction with large offshore farms.

3.3.4.2 Regulation at Zero Power

In the near future, wind farms and individual WTGs could be provided with the capability to control reactive power and therefore regulate voltage, even when they are producing no active power. This is a capability that is normally impossible to obtain from conventional generation. Separate equipment, usually controlled by the transmission owner, is normally required. One exception is synchronous condensers or GTs with clutches that can provide this service.

This capability has the potential to provide operational benefits to the system. In particular, wind farms connected at weak locations in a transmission grid could provide voltage regulation as an ancillary service. This service could, in the right application, produce significant reliability benefits, especially for the local transmission system. This issue is just beginning to receive attention in the industry, and advances in equipment and methods can be expected.

3.3.5 Forecasting

Several aspects of planning and operations, as discussed above, rely on wind production forecasts. A companion document to this report, "Overview of Wind Energy Forecasting,"[xxi] provides an in depth examination of state-of-the-art forecasting. This section provides a synopsis of key aspects of forecasting, especially as related to the experiences of the example systems.

3.3.5.1 Short term

Short term forecasting is an area of intense interest and ongoing development. A few key observations are:

1. Forecasting is getting better, but no one expects it to become perfect.
2. Forecasting must be made on each individual wind farm.
3. Generally short term forecasting (1 to 2 hours ahead) is more accurate than 6 to 72 hours ahead. Short-term projections based on "persistence" are nearly as good as more sophisticated techniques. The payoff for better methods is mainly in the 6 to 72 hour range.

4. Different measures are used to quantify how good (or bad) the forecasts are. There is no clear consensus on the preferred measure. One measure is mean absolute error (MAE). MAE is based on percent of installed generation. For short term forecasts, the MAE is typically in the 5-8% range. As the time frame increases, the MAE increases, and the difference between techniques becomes much more apparent and important. For most of the advanced techniques, the MAE tends to quickly (i.e., at about 6 hours in the future) settle to somewhere in the range of 15% to 25% error. Best in class is at the lower edge of this range.
5. There is a wide source of errors. One important source of error, i.e., of particular interest from an operations perspective, is failure to accurately predict *when* a front with substantial changes in wind speed will come through.

The European systems have invested heavily in forecasting technology to aid in system operations. With over 13,000 WTGs in operation, the German system has one of the most advanced forecasting systems in the national control center. Eltra calculates that a predicted error in wind speed of 1 m/s results in approximately 300MW power deviation for their system. For operations planning, they consider the worst case to be a 3 m/s error or 900MW.

3.3.5.2 Long Term

Some work has been done on seasonal forecasting. This issue may become important as it relates to management of hydro pondage. This is an area for further investigation.

3.3.5.3 Forecasting Summary

Good forecasting becomes progressively more important as penetration increases.

All European example systems have adopted centralized forecasting functions; everyone there seems to have concluded that pushing forecasting down to individual resources makes little or no sense. US practice to-date appears to be mixed between a relatively centralized approach and forecasting by individual wind farms. From the NYS perspective, the key point is that forecasts with a consistent format from all the individual wind farms must be available in a timely fashion to the system operators. Standard protocols and minimum standards for forecasting should be established. Some centralized processing of the forecasts, regardless of their origin will be beneficial.

Development of forecasting tools is progressing, and much can be learned from other systems. It is certain that New York State will require forecasting tools, and it is likely that customization of existing forecasting tools for the specifics of New York State will be required.

3.4 LESSONS LEARNED AND PRELIMINARY RECOMMENDATIONS

The experience of power systems with more experience with to wind generation provides insight into the policy and practices that New York State should consider. In this section, a summary of lessons learned and preliminary recommendations are presented.

3.4.1 Emerging Best Practices on Interconnection Requirements

New York State should adopt some of the requirements that have grown out of the experiences of other systems. Specifically, for all new wind projects, New York State should require wind farms to have the following features:

1. Voltage regulation at the Point-of-Interconnection, with a guaranteed power factor range specified at that point.
2. Low voltage ride-through.
3. A specified level of monitoring, metering, and event recording.
4. Power curtailment capability.

These features are available and in-use in wind farms around the world, and are proven technology. The following features are emerging in response to system needs. They are in early development, and should be required by New York State in the future as they become available.

5. Ability to set power ramp rates
6. Governor functions
7. Reserve functions
8. Zero-power voltage regulation

New York State may wish to consider a minimum wind farm size, on the order of 5 to 10MW, below which some or all of these requirements may be waived on a case-by-case basis.

3.4.2 Centralized Forecasting

For secure operation of the power system, it is essential that the system operator have wind power production forecast information for all wind facilities. Forecasts of the hourly production for each individual wind farm are required, at least, for day-ahead planning, and may be valuable for short term operations decisions as well. The combined forecasts will tend to reduce the operational importance of small local errors in wind generation predictions for individual facilities. With central collection of forecasts, major weather events and the problems they might cause can be anticipated at the system operator level. Regardless of whether responsibility for forecasting power production resides with individual wind facilities or a centralized system, a center to collect, distribute, archive and possibly enhance forecast information should be established for New York State.

3.4.3 Evolution of Technology and Procedures

New York State must recognize that both wind technology and practices are maturing quickly. The regulating and operating entities must maintain institutional flexibility that allows the adoption of new procedures. System operators have learned how wind generation affects the particular characteristics of their systems. This will undoubtedly be the case for New York State, which should begin documentation of operating experience now. Gathering experience in the near term, while wind penetration is low, will increase confidence for future operation with higher levels of penetration.

3.4.4 Operations Impacts

The largest impact of wind generation on New York State system operations is expected to be on load following reserves and unit commitment. Impact on regulation (AGC) is not expected to be substantial. The addition of wind generation increases the net load variability that must be handled by spinning reserves. The preliminary analysis shows that the addition of 10,026MW of wind generation will increase the net State load variability by about 18%. The addition of wind generation to 10% of peak load (3300 MW) will increase the net New York State load variability by about 6% (from 920MW to 975MW). This increase in variability is not expected to create significant operationing problems. At this level of penetration, any rapid drop in production from the wind farms is not expected to exceed the existing limiting contingency that determines the 10 minute operating reserve (1200 MW) for the state.

Critical objectives for the next phase of this project include developing a better understanding of New York State requirements and practices with respect to:

- Load following and regulation, and the impact of wind generation variability.
- Unit commitment, and the impact of wind forecasting accuracy.

3.4.5 Penetration Limits

It should be possible for New York State to integrate wind generation to a level of at least 10% of the system peak load – a total of about 3300MW of wind turbine-generators. The experiences of the example systems provide a good foundation on which to make this preliminary assessment. At this level of penetration, there should be no substantial operational limits or problems, provided New York State adopts wind farm requirements and operations practices as described above. Some other systems have experienced unexpectedly rapid increases in wind penetration. New York State should be able to accommodate any rate of wind generation additions at least up to this level of penetration without substantial operational limits or problems.

4. FATAL FLAW POWER FLOW ANALYSIS

The survey of world experience with wind generation, as described in the previous section, indicated that New York State should be able to accommodate at least 10% penetration (3,300MW). The primary objective of this fatal flaw power flow analysis was to determine whether the existing transmission system could accommodate this level of wind generation. Specifically, the goal was to determine the maximum power output at 101 prospective wind generation sites in various regions of New York State with the existing transmission system infrastructure. The analysis focused solely on the thermal impact of the prospective wind generation. No transmission reinforcements were evaluated.

4.1 DATA DESCRIPTION AND STUDY ASSUMPTIONS

Three 2008 power flow cases (peak load, light load, 80% peak load with high transfers) were provided by NYISO. The fatal flaw analysis was performed on two cases to examine the impact of disparate system conditions on the maximum amount of wind generation. The relatively high power transfers of the 80% peak load case suggested that more thermal limitations would be observed under that system condition. Another consideration was that the level of wind penetration is usually higher under light load conditions rather than peak load conditions. Therefore, the 80% peak load and light load cases were evaluated.

A summary of the system conditions in the three benchmark cases, with none of the prospective wind generation, is shown in Table 4.1. Total New York State generation and load as well as selected interface power flows are shown. Interface definitions are shown in Appendix A. All New York State lines and transformers at 115kV or above were within their continuous rating for the 80% peak load case. Under light load conditions, all lines and transformers at 115kV or above were within their continuous rating except for the Packard transformer, which is discussed in Section 4.3. Some branches were above their normal rating for the peak load case, as shown in Table 4.2.

All New York State bus voltages at 115kV or above were also greater than 0.95pu under 80% peak load conditions. All bus voltages at 115kV or above were greater than 0.95pu under light load conditions except for two fictitious transformer midpoint buses 75489 OAK2M115 and

75490 OAK3M115. All bus voltages at 115kV or above were greater than 0.95pu under peak load conditions except for the W. Nyack (79326) 138kV bus.

Table 4.1. Benchmark Power Flow Summary.

	80% Peak Load	Peak Load	Light Load
New York System:			
Total Generation	25,826 MW	32,525 MW	14,514 MW
Total Load	26,842 MW 11,201 MVAr	33,344 MW 13,885 MVAr	14,663 MW 6,069 MVAr
Interfaces:			
ON-NY	42 MW	72 MW	67 MW
NE-NY	-227 MW	-227 MW	-19 MW
PJM-NY	3,929 MW	3,913 MW	3,115 MW
West-Central	260 MW	241 MW	-312 MW
Central East	2,022 MW	2,023 MW	2,222 MW
Total East	3,741 MW	3,741 MW	4,747 MW
UPNY-SENY Closed	4,879 MW	4,880 MW	4,397 MW
UPNY-ConEd Closed	5,270 MW	5,270 MW	3,579 MW
ConEd Cable	3,245 MW	3,245 MW	2,611 MW
LIPA	1,442 MW	1,443 MW	1,386 MW

Table 4.2. Pre-Contingency Branch Overloads in Peak Benchmark Power Flow.

Branch Identification	Element	Loading (pu of Normal Rating)
ROCH 345-S80 1TR "1"	345/115kV Transformer	1.069
GOWANUSN-GOWNUS1T "1"	345/138kV Transformer	1.065
PACKARD2-PACK(N)E "1"	230/115kV Transformer	1.061
ASTE-WRG-CORONA-N "2"	138kV Line	1.060
GOTHLS N-GOWANUSN "1"	345kV Line	1.060
ASTORIAW-HG 5 "1"	138kV Line	1.042
GOWNUS1R-GOWNUS1T "1"	138kV Line	1.040
GOWNUS1R-GRENWOOD "1"	138kV Line	1.031
ASTE-WRG-CORONA-N "4"	138kV Line	1.025
ASTE-ERG-CORONA-S "1"	138kV Line	1.022
ASTE-WRG-HG 1 "1"	138kV Line	1.021
ASTE-ERG-CORONA-S "3"	138kV Line	1.020
GOTHLS S-GOWANUSS "1"	345kV Line	1.013
ROCH 345-S80 3TR "3"	345/115kV Transformer	1.003
ASTE-ERG-HG 4 "1"	138kV Line	1.001

Information on 101 prospective new wind sites was provided by AWS Scientific/TrueWind Solutions. It included maximum power output at each site and the closest transmission interconnection point of 115kV or higher. In addition, the sites were ranked by AWS/TrueWind in accordance with a variety of criteria including energy production capability, site topography, proximity to transmission, capital cost, and permit likelihood.

Power flow buses were identified that best matched the interconnection bus as provided in the wind generation site database. Some power flow buses matched the proposed interconnection bus exactly. In other cases, the second choice interconnection bus was the only one identified in the power flow database. In a few cases, no one-to-one correlations were identified and the nearest power flow bus was used. Finally, the power flow area identification associated with the selected interconnection bus was used, regardless of whether it matched the AWS/TrueWind zone identification. As a result, the zonal summations of prospective wind generation in the power flow analysis do not match the original AWS/TrueWind data.

The prospective wind generation sites were modeled as generators connected directly to the specified interconnection buses. No details of the transmission required between each site and the interconnection bus were modeled, i.e., no transformers, no transmission lines, no feeders. The generator power was set to the desired power output as provided in the wind site database. Each wind generator regulated the interconnection bus to the actual bus voltage before the wind generator was added. Each generator was allowed a large reactive power capability to avoid potential power flow solution difficulties due to low voltages, and to focus the analysis on the system's thermal performance.

4.2 STUDY APPROACH

This fatal flaw analysis is a thermal power flow analysis of primarily local contingencies, with a limited analysis of transmission system contingencies.

4.2.1 Local Contingency Analysis Approach

As wind generation was added to the benchmark cases, power flows between the various zones in New York State were maintained to ensure a conservative analysis. The 101 prospective wind generation sites were added to each benchmark power flow (80% peak and light load) in approximately 600MW increments following the ranking. In order to add wind generation in a particular zone and maintain inter-zone power flows, it was necessary to reduce existing generation in the same zone. Such a power output reduction, or in fact any change in generation output, is termed a redispatch. The necessary generation redispatch in this analysis was therefore performed in the local area, using units with at least a 40MW output. The redispatch followed a priority list based on plant fuel cost and heat rate data from the public domain NYS DPS RPS database. Therefore, the existing plants with the highest fuel cost were redispatched before those with a lower fuel cost. Nuclear plants were placed at the bottom of the redispatch list. The selected units were redispatched until their output reached 0MW. At that point, the unit was turned off.

Note that the wind site additions within specific zones were limited by the conservative study approach to no more than the available redispatch within that zone, i.e. the zone exchange was not modified to accommodate additional wind generation. Therefore, if the power output of the prospective wind sites was greater than the total power output of existing units available for redispatch in a particular zone, then the power output of the existing units limited the amount of wind generation that was added.

For example, a zonal summary of the 80% peak and light load benchmark cases (Table 4.3) shows that a majority of the existing generation in Zone A (Area 1) would need to be redispatched to accommodate all of the prospective wind sites. Since the wind sites will likely be reduced by local system constraints, some fraction of the existing units will remain in-service. Note, however, Zone E (Area 5) has many more prospective wind sites (2,832MW) than existing generation available for redispatch. Based on the study approach, the maximum power output of wind sites that could be added to Zone E is only about 1,100MW regardless of local system constraints.

Local contingencies, i.e., outages of each line and transformer connected to the wind generation bus, were evaluated to identify any thermal violations. Under normal conditions, all branch loadings must be below 1.00pu of each element's continuous rating. Under post-contingency conditions, all branch loadings must be below 1.00pu of each element's long term emergency rating. Several branches that represent cables were allowed loadings up to 1.00pu of the short-term emergency rating under post-contingency conditions. These branches are shown in Table 4.4.

The pre-contingency power flow solution parameters allowed action by all control devices – load tap changing (LTC) transformers, switched shunt capacitors, and phase angle regulating (PAR) transformers. No control action by any of these devices was allowed post-contingency. This analysis was performed using GE's PSLF (Positive Sequence Load Flow) software.

The limiting transmission element(s) were noted, but not upgraded or reinforced in any way. For example, the sixth ranked wind site (400MW) was limited by local thermal constraints. The maximum power output on a pre-contingency basis was 363MW under 80% peak load conditions. The maximum power output on a post-contingency basis was 353MW – otherwise the loss of the Lowville-Boonville 115kV line resulted in an overload on the Taylorville-Bremen 115kV line. Only local area overloads were identified as limiting conditions. Small overloads on remote lines were sometimes observed but ignored.

The maximum power output for each site was revised as needed in response to the pre- and post-contingency thermal analysis. Then the next 600MW block of wind sites was added, each site evaluated, and the process repeated.

Table 4.3. Zonal Generation Summary of Benchmark Cases Compared to Prospective Wind Generation Sites.

Existing In-Service Generation					
Light Load		**80% Peak Load**		**Prospective Wind Generation**	
Area 1	3,343	Area 1	4,998	Zone A	3,070
Area 2	689	Area 2	787	Zone B	1,197
Area 3	3,419	Area 3	3,714	Zone C	1,306
Area 4	1,273	Area 4	1,175	Zone D	483
Area 5	1,054	Area 5	1,138	Zone E	2,832
Area 6	219	Area 6	2,483	Zone F	434
Area 7	525	Area 7	2,123	Zone G	105
Area 8	648	Area 8	449	Zone H	0
Area 9	3	Area 9	3	Zone I	0
Area 10	1,924	Area 10	6,048	Zone J	0
Area 11	1,416	Area 11	2,908	Zone K	600
	14,513 MW		**25,826 MW**		**10,027 MW**

Table 4.4. Branches (i.e, Cables) with Short Term Emergency Criteria.

Branch Identification
Dunwoodie-Rainey "3" 345kV Line
Dunwoodie-Rainey "4" 345kV Line
Sprainbrook-W. 49th St. "1" 345kV Line
Sprainbrook-W. 49th St. "2" 345kV Line
Sprainbrook-Tremont "1" 345kV Line
Farragut-Rainey "1" 345kV Line
Farragut-Rainey "2" 345kV Line
Farragut-Rainey "3" 345kV Line
E. 15th St. 45-Farragut "1" 345kV Line
E. 15th St. 45-W. 49th St. "1" 345kV Line
E. 15th St. 46-Farragut "1" 345kV Line
E. 15th St. 46-W. 49th St. "1" 345kV Line
E. 15th St. 47-Farragut "1" 345kV Line
E. 15th St. 47-Astor "1" 345kV Line
E. 15th St. 48-Farragut "1" 345kV Line
E. 15th St. 48-Astor "1" 345kV Line
Farragut-Gowanus N. "1" 345kV Line
Farragut-Gowanus S. "1" 345kV Line
Goethals N.-Gowanus N. "1" 345kV Line
Goethals S.-Gowanus S. "1" 345kV Line

4.2.2 Transmission System Contingency Analysis Approach

The final system (as much New York State wind generation in service as possible on the basis of local contingency limitations) was then evaluated for its performance in response to transmission system contingencies under 80% peak load conditions only. The analysis used a relative performance approach to determine the impact of the prospective wind generation on the New York power system. First, system performance without any new wind generation was determined in order to establish the benchmark. Then system performance with maximum wind generation was determined and compared to the benchmark. This relative approach removed any ambiguities as to the actual impact of the proposed project since existing criteria violations, if any, were identified.

The five contingency files provided by NYISO were combined into one, removing all duplicates, and converted to a format usable by GE's PSLF software. More than 500 contingencies were included in the final list, representing various single high voltage transmission line, single large generating unit, as well as multiple element and stuck breaker outages. The thermal performance of the maximum wind generation case in response to these contingencies was compared to that of the benchmark power flow. The same thermal criteria and solution parameters were used for this transmission system contingency analysis as were used for the local contingency analysis.

All branches in New York State at 115kV or higher were monitored. Any changes in loading that were less than 3% from pre- to post-contingency were ignored. Any changes in loading that were less than 3% from the benchmark case to the maximum wind generation case were also ignored. This tolerance was used because of the inherent inaccuracies in large databases.

4.3 LOCAL CONTINGENCY ANALYSIS RESULTS

The results of the local contingency analysis for the 80% peak load case are summarized in pages 1 and 2 of Appendix B. The results of the analysis for the light load case are summarized in pages 3 and 4 of Appendix B.

The tables in Appendix B show the AWS/TrueWind site ranking and zone identification in the first two columns. The next four columns identify power flow information: interconnection bus voltage level (kV), power flow area number, wind site power output (MW), and a running sum of all prospective wind generation (MW). The next three columns identify the total wind generation (MW) added in each block, the units used in the redispatch, and the area in which the redispatch was performed. The next four columns identify the worst of any thermal overloads observed with all lines in service, i.e., pre-contingency overloads. This information includes the overloaded element, element rating (MVA), loading level (pu), and the reduced site power output required to eliminate the identified thermal violation. The next four columns identify the worst of any thermal overloads observed under post-contingency conditions. This information includes the overloaded element, element rating (MVA), loading level (pu), and the outage that caused the overload. The final four columns identify the reactive power provided by each wind generation facility (MVAr), interconnection bus voltage (pu), the final power output required to meet both pre- and post-contingency thermal criteria (MW), and a running sum of the final power output for prospective sites (MW).

Important information in each summary spreadsheet is highlighted in red or blue. Red indicates a reduction in site power output from the proposed level to a level that meets pre-contingency and/or post-contingency thermal criteria. Red also highlights comments that identify when no more units were available for redispatch in a given area, and when a particular site could not accommodate any more wind generation facilities. Blue is used in the power flow area number column to indicate a difference between the power flow area and the AWS/TrueWind zone identification.

During the evaluation, two branches received special treatment. First, it was observed that almost all outages in the Dunkirk area resulted in overloads on the Falconer-Warren 115kV line, which runs between western New York and western Pennsylvania. In previous studies, it was learned that overloads on this line are addressed by tripping it. Therefore, the Falconer-Warren 115kV line was tripped whenever its loading exceeded its long term emergency rating.

Second, high reactive power flow was observed on one of the Packard 230/115kV transformers in each of the benchmark cases. The power flow was 45MW, 128MVAr or 97% of transformer rating in the benchmark 80% peak load case. It was 111MW, 114MVAr or 113% of continuous rating in the benchmark light load case. It was 7MW, 141MVAr or 100% of rating in the summer peak load case. Therefore, this element was not allowed to limit the amount of wind generation added at any bus since it represents a pre-existing condition.

A summary of the system conditions in the final cases, with the maximum amount of prospective wind generation in-service, is shown in Table 4.5. Total New York State generation and load as well as selected interface flows are shown. Interface definitions are shown in Appendix A.

All New York State bus voltages at 115kV or above were greater than 0.95pu under 80% peak load conditions with the maximum wind generation. This represents a measure of generally acceptable performance, but is not equivalent to a voltage analysis using actual NYISO voltage criteria.

All New York State bus voltages at 115kV or above were greater than 0.95pu under light load conditions with the maximum wind generation, except for the 75489 OAK2M115 and 75490 OAK3M115 buses. However, voltages on both buses were higher in the maximum wind generation case than in the benchmark light load case. Regardless, these buses represent fictitious midpoints in transformer models and are, therefore, irrelevant.

All New York State lines and transformers at 115kV or above were within their continuous rating, under 80% peak load conditions with maximum wind generation, except as shown in Table 4.6. The Packard transformer was discussed above, and ignored throughout the analysis. The Eelpot Rd-Flat St 115kV line exhibited minor overloads throughout the analysis, even for the addition of wind generation in remote locations. It was not identified as a limiting line in the fatal flaw analysis because it was not in the same power flow area as the added wind generation. As a result, the flow on this line now exceeds the normal continuous rating.

Similarly, all New York State lines and transformers at 115kV or above were within their continuous rating, under light load conditions with maximum wind generation, except as shown in Table 4.6. Overloads on the STA 162-STA 158S and COLDS115-CARR CRN 115kV lines were ignored during the analysis in favor of limiting branches that were local to the wind generation sites. As a result, the flow on these lines now exceed the normal continuous rating. The small overloads on the E179 ST-HG 4 and E179 ST-HG 1 138kV lines were observed with the addition of site 101. Again, they were not identified as limiting lines in the fatal flaw analysis because they were not in the same power flow area.

The fact that some pre-contingency branch overloads slipped through the fatal flaw screening is an inadequacy that will be rectified in the Phase II analysis. Its impact, however, is minor. To respect the thermal criteria on these lines will require a reduction in wind generation. However, that reduction will likely be on the order of tens of MWs and will, therefore, not significantly change the results of this analysis. To estimate the likely reduction, it was assumed that the amount of wind generation reduction must be at least as large as the amount of branch overloading. Under 80% peak load conditions, the Eelpot Rd-Flat St 115kV line overload was approximately 10MW. Under light load conditions, the sum of the STA 162-STA 158S 115kV, COLDS115-CARR CRN 115kV, E179 ST-HG 4 138kV and E179 ST-HG 1 138kV line overloads was approximately 25MW. Therefore, all maximum wind generation levels derived from this analysis will be rounded down to the nearest 100MW.

Table 4.5. Maximum Wind Power Flow Summary.

	80% Peak Load		Light Load	
Wind Generation:	*Prospective*	*In-Service*	*Prospective*	*In-Service*
Zone A/Area 1	3,070	2,750	3,070	2,781
Zone B/Area 2	1,197	551	1,197	482
Zone C/Area 3	1,306	1,021	1,306	1,233
Zone D/Area 4	483	483	483	483
Zone E/Area 5	2,832	558	2,832	559
Zone F/Area 6	434	263	434	434
Zone G/Area 7	105	105	105	105
Zone H/Area 8	0	0	0	0
Zone I/Area 9	0	0	0	0
Zone J/Area 10	0	0	0	0
Zone K/Area 11	600	80	600	48
Total	10,027 MW	5,811 MW	10,027 MW	6,125 MW
New York System:				
Total Generation	25,826 MW		14,514 MW	
Total Load	26,840 MW 11,198 MVAr		14,664 MW 6,069 MVAr	
Interfaces:				
ON-NY	22 MW		85 MW	
NE-NY	-225 MW		-19 MW	
PJM-NY	4,836 MW		3,492 MW	
West-Central	-227 MW		-591 MW	
Central East	2,316 MW		2,354 MW	
Total East	4,921 MW		5,244 MW	
UPNY-SENY Closed	5,549 MW		4,931 MW	
UPNY-ConEd Closed	4,835 MW		3,579 MW	
ConEd Cable	2,715 MW		2,612 MW	
LIPA	1,454 MW		1,380 MW	

Table 4.6. Pre-Contingency Branch Overloads in Power Flows with Maximum Wind Generation.

Branch Identification	Element	Loading (pu)
80% Peak Load		
PACKARD2-PACK(S)W	230/115kV Transformer	1.45
EELPO115-FLATS115	115kV Line	1.09
Light Load		
STA 162-STA 158S	115kV Line	1.33
COLDS115-CARR CRN	115kV Line	1.06
E179 ST-HG 4	138kV Line	1.02
E179 ST-HG 1	138kV Line	1.02

4.4 LOCAL CONTINGENCY ANALYSIS DISCUSSION

The local contingency analysis restricted the maximum amount of wind generation such that pre- and post-contingency branch loading met criteria, given the existing transmission system. No transmission reinforcements were evaluated. The conservative study assumptions also resulted in limitations based upon the amount of generation available for redispatch in any given zone.

4.4.1 80% Peak Load Conditions

The results show that of the approximately 10,000MW of prospective wind generation, the transmission system can accommodate about 5,800MW under 80% peak load system conditions.

The amount of wind generation added to Zone E was largely restricted by the amount of generation available for redispatch, per the study assumptions. Specifically, 2,832MW of wind generation was proposed for Zone E (Area 5) with only about 1,100MW of existing generation available for redispatch. Under 80% peak load conditions, 558MW of wind generation was accommodated in that zone.

Zone B (Area 2) was the most limiting with respect to thermal criteria. Of the 10 prospective wind generation sites in that area, six were limited by local transmission system performance under 80% peak load conditions.

The majority of the generation available for redispatch in Zones B and C (Areas 2 and 3) was nuclear generation. Even though all nuclear plants were at the bottom of the priority list, the Ginna and 9 Mile Pt 2 units were redispatched to accommodate wind generation in Zones B and C, respectively, under 80% peak load conditions. If the nuclear plants are treated as both must-run and non-dispatchable, then the maximum amount of wind generation in Zone B is reduced by 379MW to 172MW, and the maximum amount of wind generation in Zone C is reduced by 260MW to 761MW. Thus, the total maximum wind generation under 80% peak load conditions would be reduced to about 5,100 MW.

One wind generation project (600MW) was proposed for Zone K (Area 11) at a single 345kV bus. The amount of wind generation added was only 80MW, to respect thermal limits on the Dunwoodie-Shore Rd 345kV line. It would be possible to add more wind generation in Zone K if that single project were instead several projects interconnected to a number of different buses.

The highest positive reactive power output at a wind site (116MVAr) was observed at site 85. The reactive power was required to meet the scheduled voltage on this bus, 1.04pu. However, a 50MW wind site would have a maximum reactive power capability of about 20MVAr, without additional mechanically switched capacitors or other reactive power devices. Additional analysis would be required to determine if the scheduled bus voltage could be achieved with additional equipment, or reduced, such that less reactive power would be required.

Similarly, the highest negative reactive power output (-204MVAr) was observed at site 52. The reactive power was required to meet the scheduled voltage on this bus, 1.03pu. However, a 112MW wind site would have a maximum reactive power capability of about -45MVAr, without additional mechanically switched shunt reactors or other reactive power devices. Additional analysis would be required to determine if the scheduled bus voltage could be achieved with additional equipment, or increased, such that less negative reactive power would be required.

4.4.2 Light Load Conditions

The results show that of the approximately 10,000MW of prospective wind generation, the transmission system can accommodate about 6,100MW under light load system conditions. Given the redispatch approach, a lower maximum wind generation level might be expected for the light load case than for the 80% peak load case, due to the 44% reduction in existing in-service generation. However, the generation reduction is primarily accomplished in Zones F, G and J which have few prospective wind sites. The largest zonal increase in maximum wind generation from the 80% peak load case to the light load case was observed in Zone C (Area 3), where fewer local system constraints occurred.

Again, the amount of wind generation added to Zone E was largely restricted by the amount of generation available for redispatch, per the study assumptions. Specifically, 2,832MW of wind generation was proposed with only about 1,100MW of existing generation available for redispatch. Under light load conditions, 559MW of wind generation was accommodated in that zone.

Zone B (Area 2) was the most limiting with respect to thermal criteria. Of the 10 prospective wind generation sites in that area, five were limited by local transmission system performance under light load conditions.

The majority of the generation available for redispatch in Zones B and C (Areas 2 and 3) was again nuclear generation. Even though all nuclear plants were at the bottom of the priority list, the Ginna and 9 Mile Pt 2 units were redispatched to accommodate wind generation in Zones B and C, respectively, under light load conditions. If the nuclear plants are treated as both must-run and non-dispatchable, then the total maximum amount of wind generation in under light load conditions would be reduced by about 1,176MW to about 4,900MW.

One wind generation project (600MW) was proposed for Zone K (Area 11) at a single 345kV bus. The amount of wind generation added was only 48MW, to respect thermal limits on the Dunwoodie-Shore Rd 345kV line. It would be possible to add more wind generation in Zone K if that single project were instead several projects interconnected to a number of different buses.

The highest positive reactive power output at a wind site (60.4MVAr) was observed at site 98. The reactive power was required to meet the scheduled voltage on this bus, 1.05pu. However, a wind site of this size would have a maximum reactive power capability of about 40MVAr, without additional mechanically switched capacitors or other reactive power devices. Additional analysis would be required to determine if the scheduled bus voltage could be achieved with additional equipment, or reduced, such that less reactive power would be required.

Similarly, the highest negative reactive power output (-44.4MVAr) was observed at site 21. The reactive power was required to meet the scheduled voltage on this bus, 1.03pu, and is within the maximum reactive power capability of about -65MVAr.

4.5 TRANSMISSION SYSTEM CONTINGENCY ANALYSIS RESULTS

The goal of the transmission system contingency analysis was to determine whether system performance with a high level of wind generation was significantly different than performance of the benchmark case. Specifically, the thermal performance of the benchmark and wind generation cases in response to more than 500 contingencies was evaluated under 80% peak load conditions. Forty (40) contingencies did not solve using the automatic contingency processor for the benchmark 80% peak load case. Thirty three (33) contingencies did not solve for the corresponding maximum wind generation case. Due to the preliminary nature of this Phase I assessment, no effort was made to investigate the reasons behind the lack of solution or to manually solve any of these unsolved contingencies. Therefore, no conclusions were reached on the basis of the number of unsolved contingencies.

Pre-contingency branch loading violations, if any, are shown in Table 4.7. These are the same loading violations discussed in Section 4.3. As previously noted, the high level of reactive power flow on the Packard transformer was a pre-existing condition. While noted in the pre-contingency results, it was ignored in the post-contingency analysis.

Table 4.7. Transmission System Pre-Contingency Overloads for 80% Peak Load Case.

Overloaded Element	Rated MVA	Benchmark (pu)	Maximum Wind (pu)
EELPO115-FLATS115 115kV line	111	0.00	1.09
PACKARD2 230/115kV Transformer	141	1.00	1.45

Post-contingency branch loading violations are shown in Table 4.8. The overloaded element is identified in the first column, and its long-term emergency (LTE) rating is shown in the second column. The third and fourth columns identify the worst-case contingency name and identification number. The loading results for the benchmark and maximum wind cases are shown in columns five and six. Loadings in excess of the rating are highlighted in red. DNS indicates that the contingency did not solve. Zero indicates that the loading was less than 50% of line rating and therefore, not recorded. The seventh column provides a detailed description of the worst-case outage, and the final column shows the frequency of occurrence. For example, the first row shows that the Bath-Bennett 115kV line was overloaded to 1.06pu of the 139MVA LTE rating in response to the Hill 230kV stuck breaker contingency (SB:HILL_230) under maximum wind 80% peak load conditions. This was the worst-case outage for this line, which was overloaded for a total of 3 contingencies in this analysis. In addition, the table is structured such that all branch loading violations due to a particular worst-case contingency are grouped together.

4.6 TRANSMISSION SYSTEM CONTINGENCY ANALYSIS DISCUSSION

The Hill 230kV stuck breaker outage (SB:HILL_230) was the worst-case contingency for overloads on the Bath-Bennett (1.06pu), Eelpot Rd.-Flat St. (1.26pu), and Flat St.-Greenidge (1.03pu) 115kV lines under the maximum wind 80% peak load conditions. No overloads were observed on these lines under benchmark 80% peak load conditions.

The Moses-Willis-Plattsburgh and PV20 outage (TWR:MWP&PV20) resulted in six branch overloads on the benchmark system, but no overloads on the maximum wind generation system.

The Alps-Reynolds 345kV line and Reynolds 345/115 transformer outage (Alps 345/115) resulted in overloads, or near overloads, on the Curry Rd-Rotterdam-Pine Tap W-Woodlawn

115kV line for both the benchmark and maximum wind system conditions. The addition of wind generation increased those overloads by approximately 4%. Note that in the benchmark system with all lines in service, the Curry Rd-Rotterdam 115kV line segment was already loaded to 93% of its normal rating (116MVA vs. 120MVA LTE rating) leaving little capacity for a pickup of additional flow in response to an outage.

The Dunkirk 230kV stuck breaker outage (SB:DUNK_230) results in a significant overload (1.22pu) of the Dunkirk 230/115kV transformer. This overload was not observed in the maximum wind generation system and is likely due to the Dunkirk generation reduction performed as part of the necessary redispatch.

The Stolle Rd 230kV stuck breaker outage (SB:STOL_230) resulted in an overload (1.03pu) on the Meyer-S. Perry 115kV line under benchmark 80% peak load conditions only. The loading was 0.99pu under maximum wind generation conditions.

The Sawyer 230kV towers 77 and 78 outage (TWR:77&78) resulted in overloads on the MLPN-130-PACK(S)W, NI.B-181-PACK(N)E, and ZRMN-133-OXBOWNUG 115kV lines under benchmark 80% peak load conditions only. No overloads were observed under maximum wind generation conditions.

The first Rochester 345kV stuck breaker outage (SB:ROCH_345 1) resulted in an overload (1.06pu) on the Mortimer-Sweden 115kV line under maximum wind generation conditions. The loading was 0.73pu under benchmark 80% peak load conditions.

The Coopers Corners 345kV towers 41 and 33 outage (TWR:41&33) resulted in overloads on the N.SCOT1-UNVL 7TP-OW CRN E-BOC 7T 115kV line segments under maximum wind generation conditions. No overloads were observed under benchmark 80% peak load conditions.

The Niagara 230kV towers 61 and 64 outage (TWR:61&64) resulted in an overload (1.02pu) of PACKARD2-NIAGAR2W 230kV line under benchmark conditions. No overload was observed under maximum wind generation conditions.

The second Rochester 345kV stuck breaker outage (SB:ROCH_345 2) resulted in an overload (1.03pu) of the S82-1115-S82-2115 115kV line under maximum wind generation conditions. The loading was 0.77pu under benchmark 80% peak load conditions.

The Gardenville 230kV stuck breaker outage (SB:GARD_230) resulted in overloads on the Sawyer 230kV bus ties under benchmark conditions. No overload was observed under maximum wind generation conditions.

The Erie E-S Ripley 230kV and Warren-Falconer 115kV line outage (EF/WF) resulted in an overload of the SLVRC115-NANG-141 115kV line under maximum wind generation conditions. No overload was observed under benchmark 80% peak load conditions.

The Rock Tavern 345kV stuck breaker outage (SBO:ROCK_345) with modifications due to the Calpine project did not solve under benchmark 80% peak load conditions, and resulted in a significant overload (1.54pu) on the Sugar Loaf-Rock Tavern 115kV line under maximum wind generation conditions.

Similarly, the Newbridge 1420 outage (15: NBR 1420) did not solve under benchmark 80% peak load conditions, and resulted in an overload (1.13pu) on the Valley Stream-E. Garden City 115kV line under maximum wind generation conditions.

The Ramapo 70-2Y (SB:RMP70-2Y) and 69-2Y (SB:RMP69-2Y) stuck breaker outages resulted in overloads on the Waldwick-S Mahwah 1 345kV (1.08pu) and Waldwick-S Mahwah 2 345kV (1.30pu) lines, respectively, under maximum wind generation conditions. No overloads were observed under benchmark 80% peak load conditions.

In general, this preliminary transmission system analysis showed that the impact of the additional wind generation was mixed. It improved thermal performance in response to some outages and reduced it in response to others. Additional analysis would be required to determine the relative impact due to each wind generation project and the associated redispatch, as well as any mitigation requirements.

Table 4.8. Transmission System Post-Contingency Overloads for 80% Peak Load Case.

Overloaded Element	Rated MVA	ID	#	Benchmark	Maximum Wind	Outage description	Freq
BATH 115-BENET115 115kV	139	SB:HILL_230	195	0.61	1.06	line from AVOCA230 230 to HILSD230 230 line from HILSD230 230 to WATRC230 230 tran from HILSD230 230 to HILSD M3 34.50 line from E.TWANDA 230 to HILSD230 230	3
EELPO115-FLATS115 115kV	131			0.00	1.26		3
FLATS115-GRNDG115 115kV	128			0.00	1.03		3
BRAIN115-CHATP115 115kV	131	TWR:MWP&PV20	35	1.20	0.00	line from MOSES W 230 to WILLIS E 230 line from PLAT T#1 230 to WILLIS E 230 tran from WILL 115 115 to WILLIS E 230 line from MOSES W 230 to WILLIS W 230 line from PLAT T#4 230 to WILLIS W 230 tran from WILL 115 115 to WILLIS W 230 tran from PLAT 115 115 to PLAT T#3 115 line from PLAT T#3 115 to PLAT 115 115	2
CHATP115-WILL 115 115kV	131			1.27	0.00		1
KENTS115-LYONS115 11kV	152			1.04	0.00		1
MALONE -WILL 115 115kV	119			1.40	0.00		1
PLAT 115-T MIL RD 115kV	123			1.14	0.00		1
SARANAC -T MIL RD 115kV	123			1.12	0.00		1
CURRY RD-RTRDM1 115kV	120	Alps 345/115	344	1.16	1.20	line from ALPS345 345 to REYNLD3 345 tran from REYNLD3 345 to REY. RD. 115	10
PINETAPW-RTRDM1 115kV	120			1.06	1.10		7
PINETAPW-WOODLAWN 115kV	120			0.97	1.01		1
DUNKIRK 230/115kV	177	SB:DUNK_230	256	1.22	0.00	line from DUNKIRK 230 to GRDNVL2 230 tran from DUNKIRK 230 to DUNKIRK1 115 line from DUNKIRK 230 to S RIPLEY 230	1
MEYER115-S.PER115 115kV	96	SB:STOL_230	240	1.03	0.99	line from GARDV230 230 to STOLE230 230 line from ROBIN230 230 to STOLE230 230 line from MEYER230 230 to STOLE230 230	1
MLPN-130-PACK(S)W 115kV	185	TWR:77&78	42	1.05	0.00	line from SAWYER77 230 to HUNTLEY2 230 line from SAWYER77 230 to PACKARD2 230 line from SAWYER78 230 to HUNTLEY2 230 line from SAWYER78 230 to PACKARD2 230	1
NI.B-181-PACK(N)E 115kV	166			1.01	0.00		1
ZRMN-133-OXBOWNUG 115kV	185			1.05	0.00		1

Table 4.8 (continued). Transmission System Post-Contingency Overloads for 80% Peak Load Case.

Overloaded Element	Rated MVA	ID	#	Benchmark	Maximum Wind	Outage description	Freq
MORTIMER-SWDN-111 115kV	136	SB:ROCH_345 1	272	0.73	1.06	line from NIAG 345 345 to ROCH 345 345 tran from ROCH 345 345 to S80 1TR 115	6
N.SCOT1 –UNVL 7TP 115kV	120	TWR:41&33	23	0.00	1.09	line from COOPC345 345 to MARCY T1 345 line from COOPC345 345 to FRASR345 345	5
OW CRN E-BOC 7T 115kV	120			0.00	1.02		1
OW CRN E-UNVL 7TP 115kV	120			0.00	1.09		5
PACKARD2-NIAGAR2W 230kV	649	TWR:61&64	36	1.02	0.91	line from PACKARD2 230 to NIAGAR2W 230 line from ROBIN230 230 to NIAGAR2E 230	2
S82-1115-S82-2115 115kV	400	SB:ROCH_345 2	277	0.77	1.03	line from ROCH 345 345 to PANNELL3 345 tran from S80 2TR 115 to ROCH 345 345	2
SAWYER77-SAWYERB1 230kV	140	SB:GARD_230	492	1.04	0.61	line from DUNKIRK 230 to GRDNVL2 230 line from SAWYER80 230 to HUNTLEY2 230	1
SAWYER78-SAWYERB2 230kV	140			1.05	0.61		1
SAWYER80-SAWYERB3 230kV	140			1.11	0.00		2
SLVRC115-NANG-141 115kV	101	EF/WF	307	0.00	1.04	line from ERIE E 230 to S RIPLEY 230 line from WARREN 115 to FALCONER 115	4
SUGARLF -ROCK TV1 115kV	204	SBO:ROCK_345 (Calpine Mods)	368	DNS	1.54	line from ROCK TAV 345 to CALPINE 345 line from ROCK TAV 345 to RAMAPO 345 line from SHOEM 138 to SHOEMTAP 138	8
VLY STRM-E.G.C.-2 138kV	290	15: NBR 1420	404	DNS	1.13	line from NEWBRGE 138 to RULND RD 138 line from FREEPORT 138 to NEWBRG-2 138 tran from NEWBRG-2 138 to NEWBRGE2 69	2
WALDWICK-SMAHWAH1 345kV	905	SB:RMP70-2Y	138	0.00	1.08	tran from RAMAPO 345 to RAMAPO 1 138 tran from RAMAPO 345 to RAMAPO 1 138 line from RAMAPO 345 to SMAHWAH2 345	2
WALDWICK-SMAHWAH2 345kV	898	SB:RMP69-2Y	136	0.00	1.30	tran from RAMAPO 345 to RAMAPO 1 138 tran from RAMAPO 345 to RAMAPO 1 138 line from RAMAPO 345 to SMAHWAH1 345	2

4.7 SUMMARY

The local contingency analysis restricted the maximum amount of wind generation such that pre- and post-contingency branch loading met criteria, given the existing transmission system. No transmission reinforcements were evaluated. The study assumptions also resulted in limitations based upon the amount of generation available for redispatch in any given zone.

The results show that of the approximately 10,000MW of prospective wind generation, the transmission system can accommodate about 5,800MW under 80% peak load system conditions, and about 6,100MW under light load conditions.

The majority of the generation available for redispatch in Zones B and C (Areas 2 and 3) was nuclear generation. If the nuclear plants are treated as both must-run and non-dispatchable, then the maximum wind generation under 80% peak load conditions would be reduced to about 5,100MW. Similarly, the maximum wind generation under light load conditions would be reduced to about 4,900MW.

In general, the preliminary transmission system analysis showed that the impact of the additional wind generation was mixed. It improved thermal performance in response to some outages and reduced it in response to others. Additional analysis would be required to determine the relative impact due to each wind generation project and the associated redispatch, as well as any mitigation requirements.

In summary, although some local sites may be restricted, the fatal flaw power flow analysis did not preclude the system from reaching the 10% level of penetration discussed in the survey of world experience.

5. RELIABILITY ANALYSIS

5.1 INTRODUCTION

The work scope of this project states, “Identify MW levels and associated risks above which the continued addition of wind-generation in a geographic area exceeds the transfer capability out of the area.” With respect to generation reliability, this analysis is really asking two questions about wind resources. The first is, “What is the capacity value of wind as an intermittent resource as compared to typical thermal generation?” and the second question is, “How do transmission constraints in New York State limit the capacity value of wind in the various regions of the state?” These issues need to be addressed separately in order to properly address the intermittent aspects of wind generation without penalizing wind resources for system characteristics that are equally limiting to all types of generation.

This measure of the value of an intermittent resource like wind will account not only for the hourly variability of the generation but also the hourly variability of the need for capacity. Unavailability on an off peak season or hour will tend to have much less impact than on peak. Depending on the timing of the resource it may be possible for a unit with 50% unavailability to receive 80% capacity credit or only 20%.

5.2 BACKGROUND

We will first briefly describe the model, data and modeling methodology used in the analysis.

5.2.1 GEII’s Multi-Area Reliability Simulation program (MARS)

The General Electric International, Inc. (GEII) Multi-Area Reliability Simulation program (MARS) was used to calculate the New York Control Area, NYCA, system reliability in terms of daily loss-of-load expectation (LOLE).

MARS uses a sequential Monte Carlo simulation to calculate the reliability of a generation system that is made up of a number of interconnected zones. The zones are defined based on the limiting interfaces within the transmission system. Generating units and an hourly load profile are assigned to each zone. MARS performs a chronological hourly simulation of the system, comparing the hourly load in each zone to the total available generation in the zone, which has been adjusted for planned maintenance and randomly occurring forced outages.

If a zone's available generation is less than its load, the program will attempt to deliver assistance from zones that have a surplus that hour, subject to the transfer limits between the zones. If the assistance is not available or it cannot be delivered to the deficient zone, the zone will be considered to be in a loss-of-load state for that hour, and the statistics required to compute the reliability indices will be collected. This process is repeated for all of the hours in the year. The year is then simulated hundreds of times with different random forced outages on the generating units and transmission interfaces until the simulation has converged.

The reliability calculations in MARS are done at the zone level – the generating units are assigned to zones, the hourly load profiles are defined by zone, and the interface transfer limits are modeled between zones. The NYCA system indices in MARS are computed from the zone results: If one or more of the zones in NYCA are deficient in an hour, then NYCA is considered as being deficient.

A detailed description of the MARS program can be found in Appendix C.

5.2.2 Data

The initial system data was taken from the NYISO database for the MARS program. This is the same data used for the NYISO's recent Installed Capacity Requirements study for May 2004 through April 2005. The peak loads were modified to represent the 2008 system. No additional generation was added since the existing system met the design targets of providing the New York Control Area, NYCA, with roughly 0.1 days/year Loss of Load Expectation (LOLE) on an interconnected basis. Hourly wind data was developed by TrueWind Solutions, LLC and ranked for 101 unique sites in New York State. Table 5.1 shows the characteristics and groupings of the various wind sites. The 101 sites were grouped in roughly 600MW blocks to reduce the number of discrete steps that needed to be taken in this analysis.

Table 5.1 also identified the capacity factor for each site as well as the UCAP, or Unforced Capacity. The UCAP is determined for conventional generation by multiplying the unit's capacity times one minus its forced outage rate. As an example, a 100MW unit with a forced outage rate of 10% would have a UCAP of 90MW = 100 * (1-.10). The UCAP is an easy, approximate method for measuring a unit's *effective* capacity, or how much increased load the system can carry with the unit added. If another 100MW unit had a forced outage rate of 20% then its UCAP would only be 80MW. Unlike ICAP, or Installed Capacity, which would consider these two units to have the same capacity value, UCAP recognizes the importance of the unit's availability. For energy limited devices, where the availability may be limited by other factors, the UCAP can be determined by multiplying the rating of the plant by its capacity factor. This can be viewed as an average annual rating for the plants. The capacity factor method was employed to determine the values in Table 5.1. The capacity factors listed account for both equipment and wind availability. The bulk of the capacity factors range from 25% to 30% with a handful going a bit higher. Due to the low capacity factors on wind plants it is important that UCAP, or possibly some modified version of it, be used to compare their capacity values to other generation. Table 5.2 is a summary of the installed capacity, ICAP, by group, by zone. The columns on the right hand side have further grouped the zones west of the Central East Interface as "West" and the remaining zones as "East." The Central East Interface separates zones A through E from the rest of the system and is one of the major limiting interfaces in New York. Table 5.3 shows the Unforced Capacity, UCAP, by group and zone. Figure 5.1 shows the range of capacity factors versus the plant size for all of the 101 plants being examined.

Table 5.1 Characteristics and groupings of wind sites

Rank	Zone	Capacity (MW)	Group	Annual Capacity Factor	UCAP	Rank	Zone	Capacity (MW)	Group	Annual Capacity Factor	UCAP
1	E	60.5	A	0.40	24.3	52	A	111.7	H	0.27	30.4
2	B	49.9	A	0.35	17.4	53	F	61.9	H	0.29	18.2
3	E	49.9	A	0.33	16.5	54	E	49.9	I	0.28	13.8
4	F	49.9	A	0.33	16.5	55	A	179.2	I	0.27	48.6
5	A	72.5	A	0.32	22.9	56	E	55.7	I	0.28	15.4
6	E	400.0	A	0.32	126.8	57	E	65.7	I	0.28	18.1
7	A	77.7	B	0.32	25.2	58	B	146.4	I	0.29	43.0
8	D	181.5	B	0.31	56.4	59	E	49.9	I	0.28	14.1
9	A	172.3	B	0.30	52.4	60	F	124.3	I	0.29	36.0
10	D	141.1	B	0.31	43.6	61	A	123.8	J	0.27	33.5
11	G	49.9	C	0.31	15.4	62	E	88.8	J	0.27	24.0
12	A	89.3	C	0.32	28.2	63	F	50.4	J	0.28	14.2
13	E	68.2	C	0.30	20.5	64	A	55.2	J	0.28	15.6
14	A	109.5	C	0.30	32.6	65	E	49.9	J	0.27	13.5
15	F	49.9	C	0.31	15.4	66	E	49.9	J	0.27	13.6
16	E	89.6	C	0.30	26.6	67	B	64.3	J	0.27	17.1
17	A	74.2	C	0.31	23.3	68	E	52.3	J	0.27	14.2
18	A	88.7	C	0.30	26.5	69	F	49.9	J	0.29	14.6
19	A	253.4	D	0.31	77.8	70	A	66.0	J	0.27	18.1
20	A	133.5	D	0.30	39.4	71	A	109.9	K	0.27	29.8
21	A	159.2	D	0.30	47.3	72	G	50.4	K	0.27	13.7
22	E	55.9	D	0.31	17.4	73	C	53.3	K	0.26	14.0
23	A	181.9	E	0.29	52.8	74	C	98.6	K	0.26	25.5
24	A	172.3	E	0.30	51.0	75	A	183.8	K	0.26	48.3
25	A	197.3	E	0.29	57.8	76	A	101.8	K	0.26	26.5
26	B	73.5	E	0.29	21.5	77	C	50.2	K	0.26	13.2
27	D	49.9	F	0.30	14.7	78	C	49.9	K	0.26	13.0
28	A	67.2	F	0.30	20.1	79	E	763.4	L	0.28	211.5
29	B	61.5	F	0.30	18.5	80	E	76.6	M	0.26	19.9
30	D	60.4	F	0.30	17.8	81	A	131.8	M	0.26	34.7
31	C	108.0	F	0.29	30.8	82	E	73.4	M	0.26	19.1
32	A	73.3	F	0.29	20.9	83	C	64.8	M	0.26	17.1
33	E	91.8	F	0.29	26.5	84	C	49.9	M	0.26	12.9
34	C	50.1	F	0.29	14.5	85	A	113.8	M	0.26	29.6
35	A	88.8	F	0.28	25.2	86	C	49.9	M	0.26	12.9
36	F	49.9	G	0.30	14.8	87	A	88.8	M	0.25	22.5
37	A	67.7	G	0.29	19.4	88	A	61.9	N	0.26	16.3
38	A	68.6	G	0.28	19.5	89	E	61.4	N	0.26	15.8
39	F	61.4	G	0.28	17.4	90	A	125.3	N	0.25	31.7
40	C	67.7	G	0.29	19.8	91	A	71.5	N	0.26	18.6
41	E	52.3	G	0.28	14.7	92	B	51.8	N	0.26	13.5
42	E	49.9	G	0.29	14.3	93	G	54.2	N	0.27	14.4
43	E	82.6	G	0.28	23.0	94	E	49.9	N	0.26	12.7
44	A	82.1	G	0.29	23.5	95	A	61.4	N	0.26	16.1
45	C	51.8	G	0.29	15.0	96	E	49.9	N	0.26	12.9
46	C	58.6	H	0.28	16.5	97	F	49.9	N	0.27	13.2
47	A	150.2	H	0.28	41.9	98	C	95.4	O	0.25	23.8
48	C	73.9	H	0.28	20.8	99	A	49.9	O	0.26	12.7
49	E	50.1	H	0.29	14.3	100	F	155.0	O	0.27	42.2
50	B	67.2	H	0.28	19.0	101	K	600.0	O	0.41	246.0
51	E	96.0	H	0.29	28.1						

Table 5.2 Cumulative ICAP of Wind groups by New York State zone

GROUP	ZONE A	B	C	D	E	F	G	K	Total	West	East
A	73	50	0	0	510	50	0	0	683	633	50
B	323	50	0	323	510	50	0	0	1,255	1,205	50
C	684	50	0	323	668	100	50	0	1,875	1,725	150
D	1,230	50	0	323	724	100	50	0	2,477	2,327	150
E	1,782	123	0	323	724	100	50	0	3,102	2,952	150
F	2,011	185	158	433	816	100	50	0	3,753	3,603	150
G	2,230	185	278	433	1,001	211	50	0	4,387	4,126	261
H	2,491	252	410	433	1,147	273	50	0	5,056	4,733	323
I	2,671	399	410	433	1,368	397	50	0	5,727	5,280	447
J	2,916	463	410	433	1,609	498	50	0	6,378	5,830	548
K	3,311	463	662	433	1,609	498	100	0	7,076	6,478	598
L	3,311	463	662	433	2,372	498	100	0	7,839	7,241	598
M	3,646	463	827	433	2,522	498	100	0	8,488	7,890	598
N	3,966	515	827	433	2,684	548	155	0	9,125	8,423	702
O	4,016	515	922	433	2,684	703	155	600	10,026	8,569	1,457

Table 5.3. Cumulative UCAP of Wind groups by New York State zone

GROUP	ZONE A	B	C	D	E	F	G	K	Total	West	East
A	23	17			168	17			224	208	17
B	100	17	0	100	168	17	0	0	402	385	17
C	211	17	0	100	215	32	15	0	591	543	47
D	376	17	0	100	232	32	15	0	772	725	47
E	537	39	0	100	232	32	15	0	955	908	47
F	603	57	45	133	259	32	15	0	1,145	1,097	47
G	666	57	80	133	311	64	15	0	1,326	1,246	80
H	738	76	117	133	353	82	15	0	1,515	1,417	98
I	787	119	117	133	415	118	15	0	1,704	1,570	134
J	854	137	117	133	480	147	15	0	1,883	1,720	163
K	958	137	183	133	480	147	29	0	2,067	1,890	176
L	958	137	183	133	691	147	29	0	2,278	2,102	176
M	1,045	137	226	133	730	147	29	0	2,447	2,270	176
N	1,128	150	226	133	772	160	43	0	2,612	2,408	204
O	1,140	150	250	133	772	202	43	246	2,936	2,445	492

5.2.3 Modeling methodology

The system reliability was analyzed by calculating the NYCA interconnected Loss of Load Expectation (LOLE) with varying levels of wind additions. The wind was treated as firm capacity that varied on an hourly basis. The analysis first examined the reliability value of wind based on its intermittent nature. To do that we assumed that, while the characteristics were drawn from each specific site, the wind farm outputs were all injected into the system in Zone J, New York City. This is where the greatest need for generation exists and where the benefits based on actual wind generation characteristics, as opposed to location, would show up the best. Each unit was then sited at its actual location and the analysis was repeated.

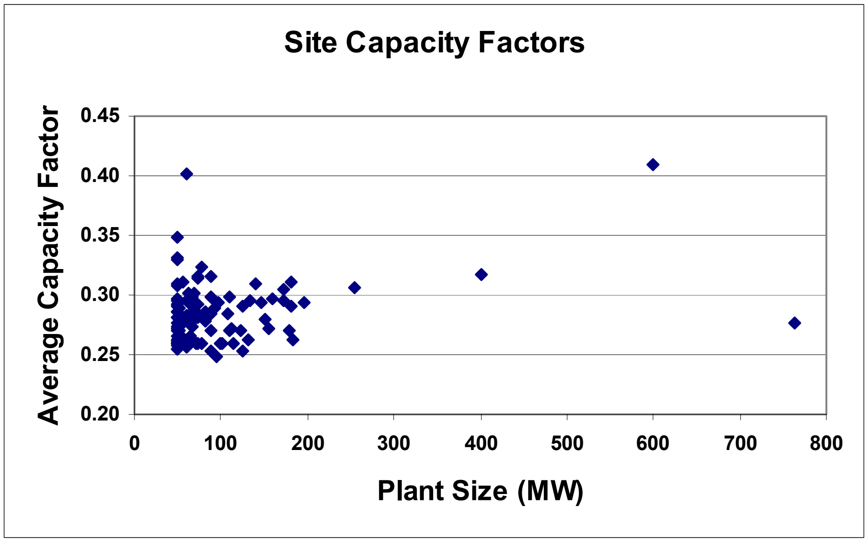

Figure 5.1 Wind site capacity factors vs. plant size

5.3 RELIABILITY RESULTS

Figure 5.2 shows the impact of the wind additions on the NYCA reliability, as measured by LOLE in days/year, when the capacity is added in either the downstate or actual site locations. The difference between the two curves represents the impact of transmission constraints.The blue curve, which shows the impact of the units being added at a downstate location, shows the reliability of the system continues to improve with increased additions of wind capacity. The red curve, representing the impact of the units being added in their actual locations, shows only a slight initial drop and then remains almost level. The drop at the very end includes the impact of 600MW being added in Long Island. The megawatts of wind output were exactly the same for both curves, however transmission constraints limited the actual reliability value of the new capacity. Figure 5.3 shows the same plots versus the UCAP of the plant additions.

A logical question at this point would be “How does this change in LOLE compare to the impact of a thermal unit?” To examine this question a 250MW thermal unit with a 10% forced outage rate was added to either an upstate or downstate location. For reference, this unit would have a UCAP of 225MW [= 250 * (1-.1)], which is roughly equal to the UCAP of the first group of wind units (Group A). Figure 5.4 shows the comparison versus the ICAP of the wind plants and Figure

5.5 compares it to UCAP of the wind plants. Again, the impact of transmission constraints is evident with the unit addition having a greater impact on reliability when installed downstate.

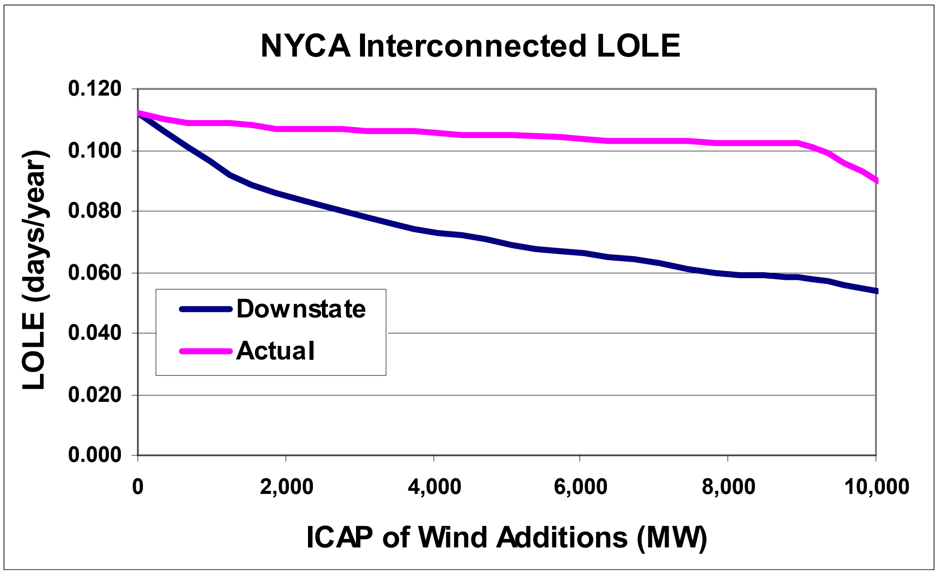

Figure 5.2 NYCA Interconnected LOLE vs. ICAP of Wind Additions

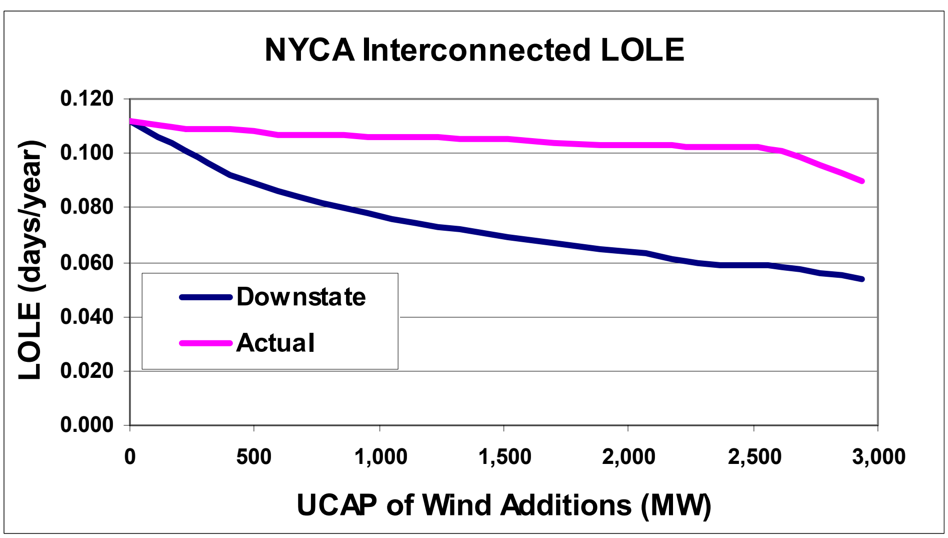

Figure 5.3 NYCA Interconnected LOLE vs. UCAP of Wind Additions

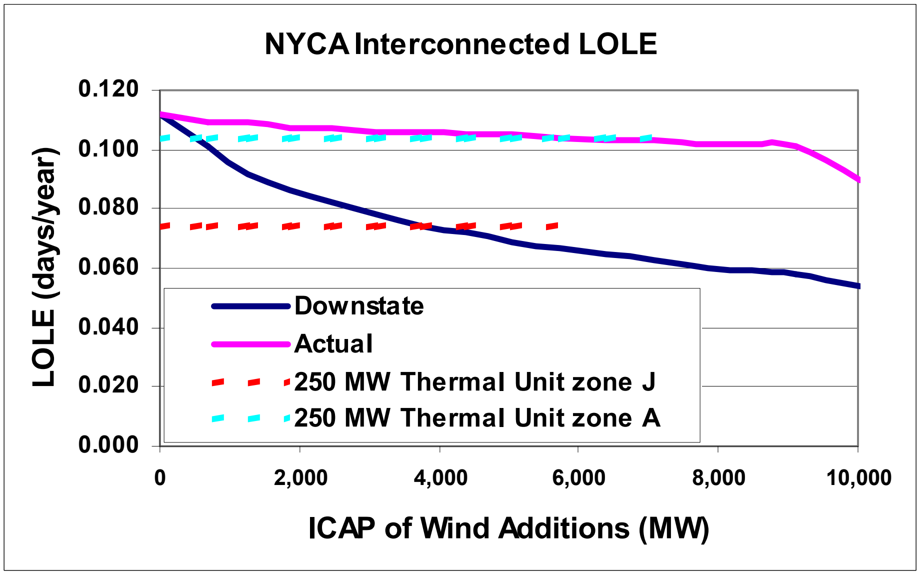

Figure 5.4 NYCA LOLE vs. ICAP including Thermal Unit

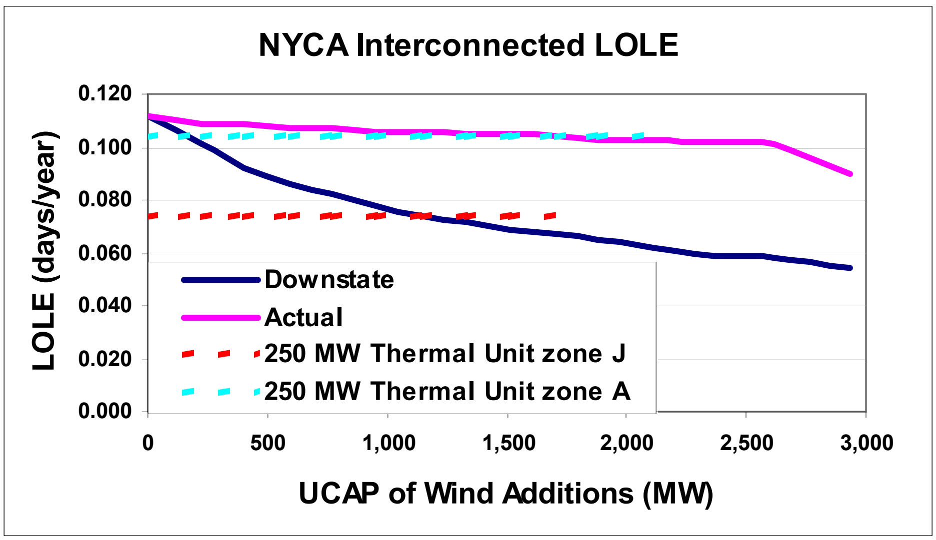

Figure 5.5 NYCA LOLE vs. UCAP including Thermal Unit

5.4 EXAMINATION OF RESULTS

The initial results were surprising in that the UCAP of wind required to achieve comparable results needed to be so much larger than for conventional generation. The 250MW thermal unit in zone J with a UCAP of 225MW reduced the LOLE to 0.074 days/year. Accomplishing that same LOLE reduction with wind plants required the addition of the first 35 sites, or up through

Group F, for a total UCAP of 1,145MW (based on the capacity factor method) and an installed capacity of 3,753MW.

As a check on the validity of the calculations we then examined the effective capacity of the thermal unit. This was done by increasing the load in area J, New York City, until the system reliability with the unit added returned to its original level. This effective capacity of the unit is the quantity that UCAP is trying to approximate. Figure 5.6 gives the results of this analysis. The downstate addition had a capacity value of about 230MW, which agrees quite closely with its UCAP of 225MW. The upstate addition would only allow the downstate load to increase by about 32MW. This is consistent with the fact that the vast majority of the generation shortages in the NYCA system are expected to occur in downstate zones. Upstate New York has sufficient capacity to meet its needs and to export up to the limits of the transmission system. While there are separate capacity markets for the New York City and Long Island zones no differentiation is made for ICAP or UCAP outside those zones. Therefore, to be consistent, wind resources should be evaluated on their inherent characteristics and not their location. Therefore we will evaluate wind based on their "downstate" results.

But the question remains, if UCAP works so well to estimate the value of conventional generation downstate why is it so far off in estimating the value of the wind?

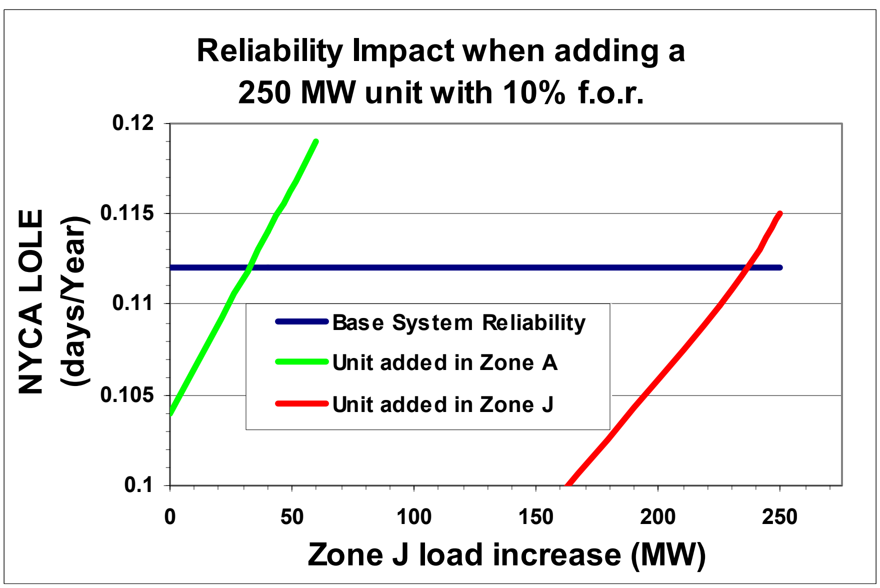

Figure 5.6 Reliability impact of thermal unit

5.4.1 More wind characteristics

To examine this question we need to examine the wind characteristics more closely. Figure 5.7 shows the monthly capacity factors for the first six wind sites that make up Group A, along with the NYCA monthly peak load. While their average annual capacity factors were all over 30%, the capacity factors in July and August, the periods when almost all of the NYCA risk of outage occurs, is only about 15% to 20%.

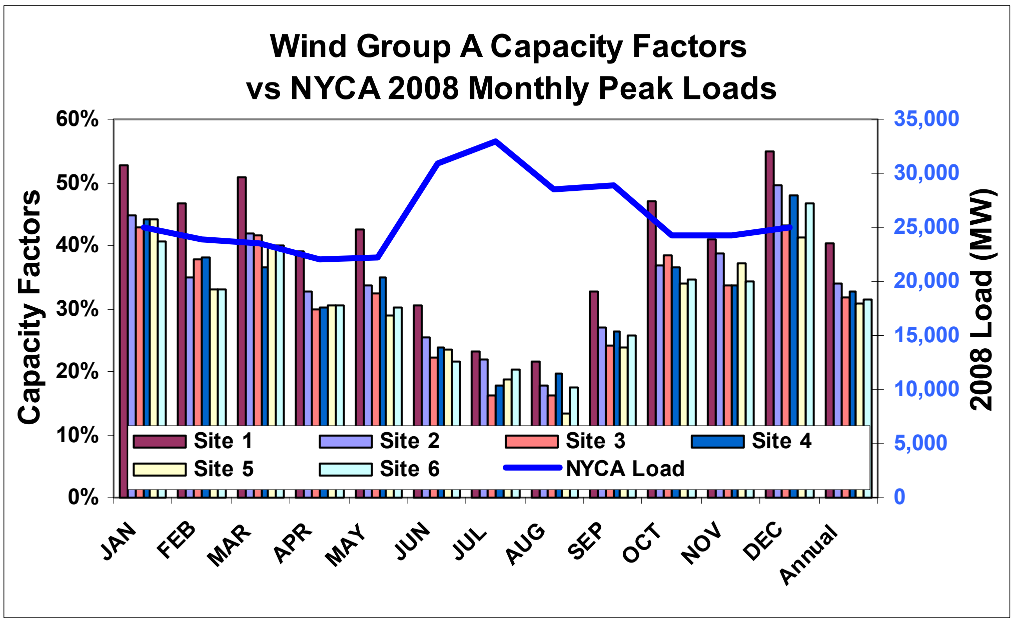

Figure 5.7 Monthly Capacity Factors for Wind Group A

Figure 5.8 illustrates the operation of wind plants on an hourly basis. The curves show the average hourly output for the sites in Group A for the month of July. A daily pattern is clearly evident.

We can compare this to the hourly load curves for the same period. Figure 5.9 shows that the NYCA system loads have a clear pattern as well, however they peak in the afternoon and evening hours rather than early in the day. Figure 5.10 shows power outputs for 31 days of operation at site 1 for the month of July along with the average power output (heavy red curve) and the average load curve (heavy blue curve). It is evident that the average loads and average wind operation are largely "out of phase" with each other. Figure 5.11 shows a similar set of curves for the total output of all 101 wind sites. The average output (shown in the heavy red curve) demonstrates the same peak through the morning hours with output in the afternoon and evening being only half of the energy shown earlier in the day.

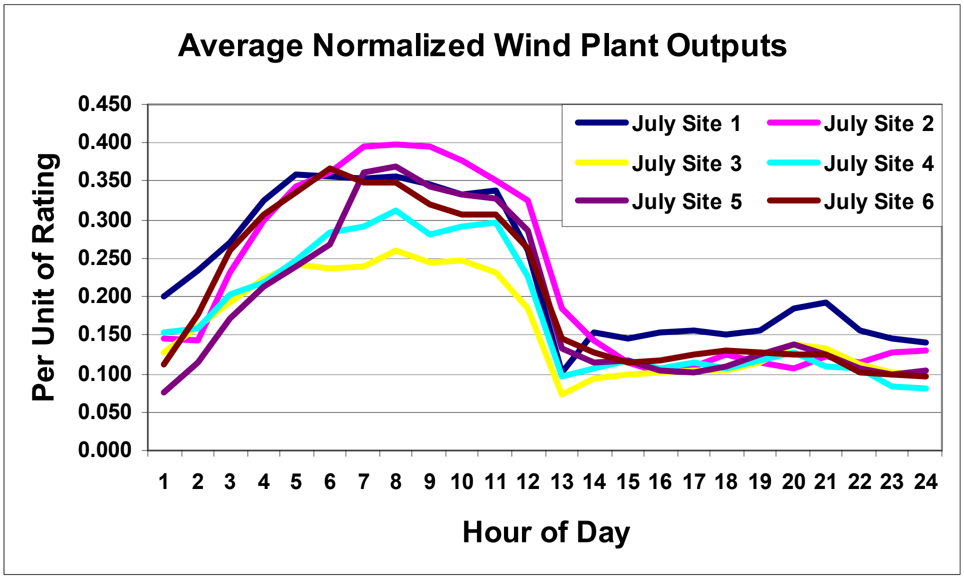

Figure 5.8 Average normalized wind plant outputs for July

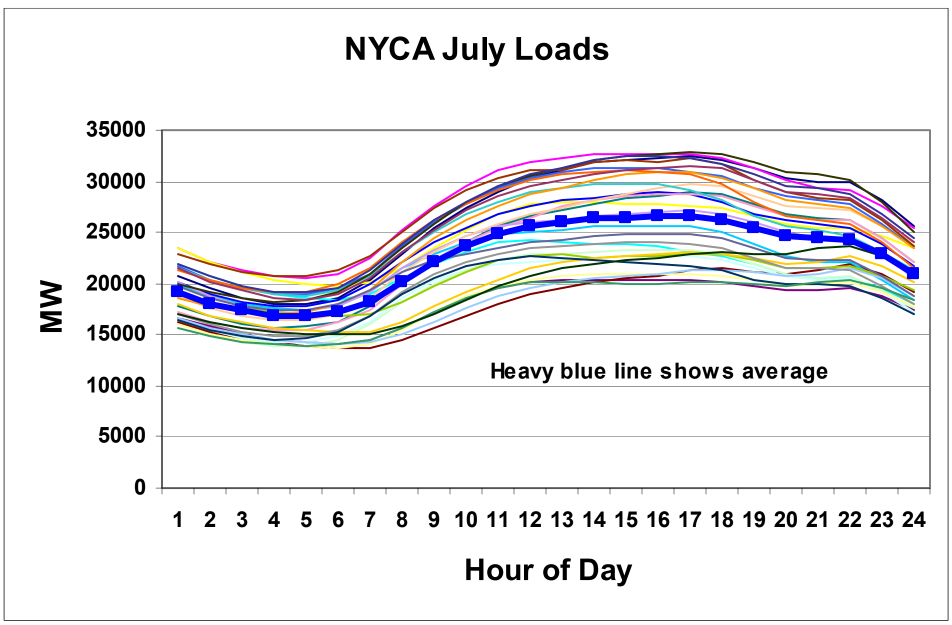

Figure 5.9 NYCA hourly loads for July 2008

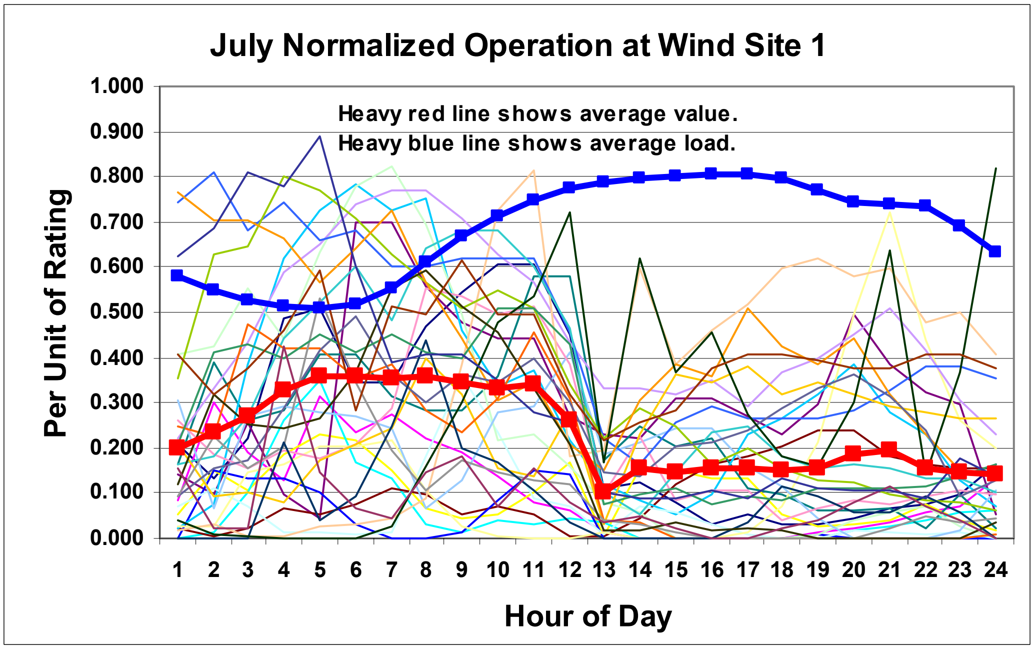

Figure 5.10 Normalized operation at wind site 1 for 31 days in July

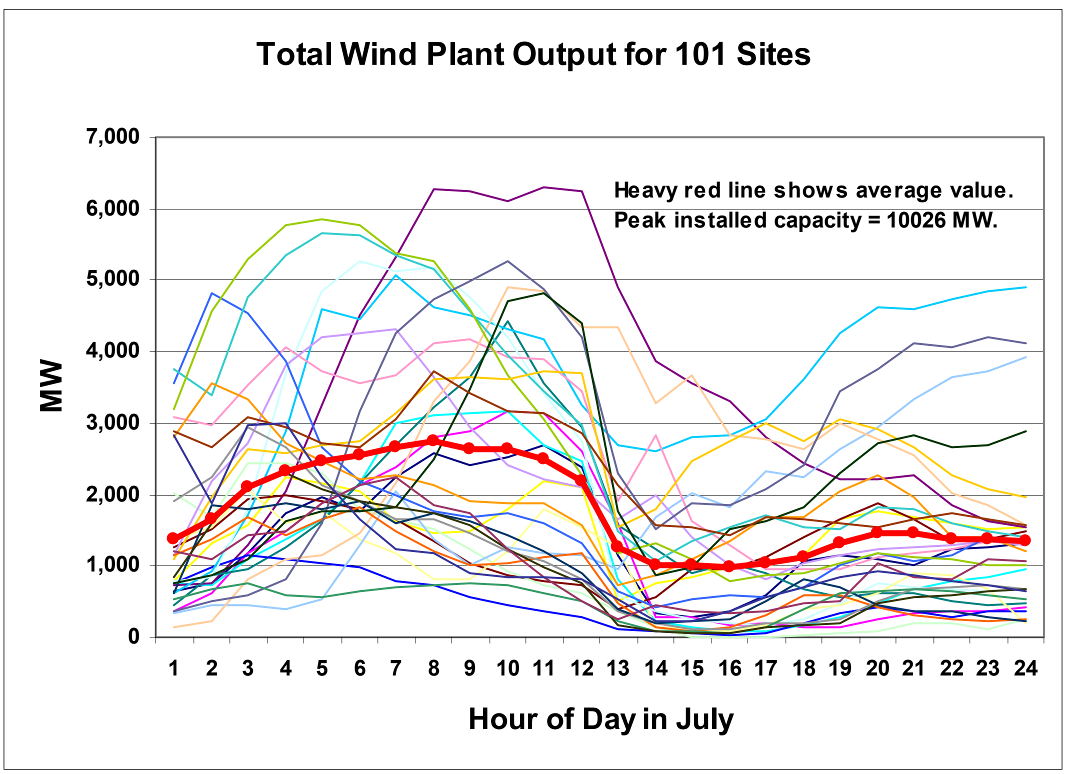

Figure 5.11 Total output for all 101 wind sites for 31 days in July.

5.4.2 Modified UCAP for Wind

The reliability impact of an intermittent source will be not only a function of the variability of its output but also how its output interacts with the hourly variability of the system need. High availability in off peak hours has no value in addressing the reliability needs of the system as measured by LOLE. As an example, we can define the peak period as those hours when the average load in Figure 5.9 is at least 75% of the monthly peak. This results in a peak period being defined as 11 a.m. to 7 p.m. Using this definition of on-peak and off-peak periods produces the results shown in Figure 5.12. The on-peak capacity factors for July and August vary from 11% to 18%. This is even lower than the monthly average capacity factors seen previously in Figure 5.7.

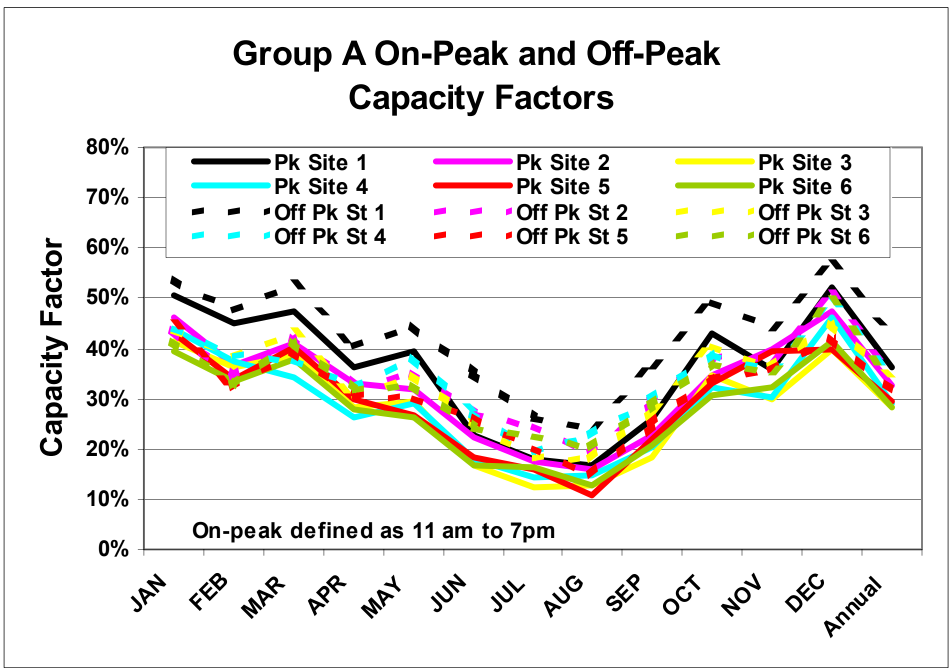

Figure 5.12 Group A On and Off peak capacity factors.

Using only the on-peak capacity factors allows us to create the modified UCAP table shown in Table 5.4. Comparing this to the previous tables we can see that while the 10,026MW of total wind capacity initially provided a total of 2,936MW of UCAP using the conventional capacity factor technique, it results in only 1,273MW of modified UCAP which reflect the wind turbines' ability to provide capacity at a time when it is needed by the system. Figure 5.13 shows the

NYCA interconnected LOLE versus this modified UCAP of wind additions. The dotted red line is at 0.074 days/year and represents the reliability impact of adding the 250MW unit in zone J. This intersects the solid blue curve, representing the downstate additions of wind, at about 500MW. This shows that a 250MW thermal unit is roughly equivalent to about 500MW of the modified UCAP of wind additions. Additional refinements to the peak period definition may close this gap even further, but clearly it is on the right path.

Table 5.4 Modified UCAP (based on peak capacity factors) of Wind Groups by NYCA zone.

	ZONE										
Group	A	B	C	D	E	F	G	K	Total	West	Down
A	10	8	0	0	74	7	0	0	100	92	7
B	44	8	0	47	74	7	0	0	181	174	7
C	93	8	0	47	96	13	6	0	262	244	19
D	164	8	0	47	105	13	6	0	344	325	19
E	237	19	0	47	105	13	6	0	427	409	19
F	266	27	20	61	116	13	6	0	509	490	19
G	289	27	34	61	137	25	6	0	580	550	30
H	318	35	50	61	157	31	6	0	659	622	36
I	341	54	50	61	181	44	6	0	738	688	50
J	370	62	50	61	207	54	6	0	811	751	60
K	409	62	79	61	207	54	11	0	883	818	65
L	409	62	79	61	297	54	11	0	973	908	65
M	447	62	96	61	311	54	11	0	1,043	978	65
N	482	67	96	61	327	59	16	0	1,109	1,034	75
O	487	67	106	61	327	75	16	134	1,273	1,048	225

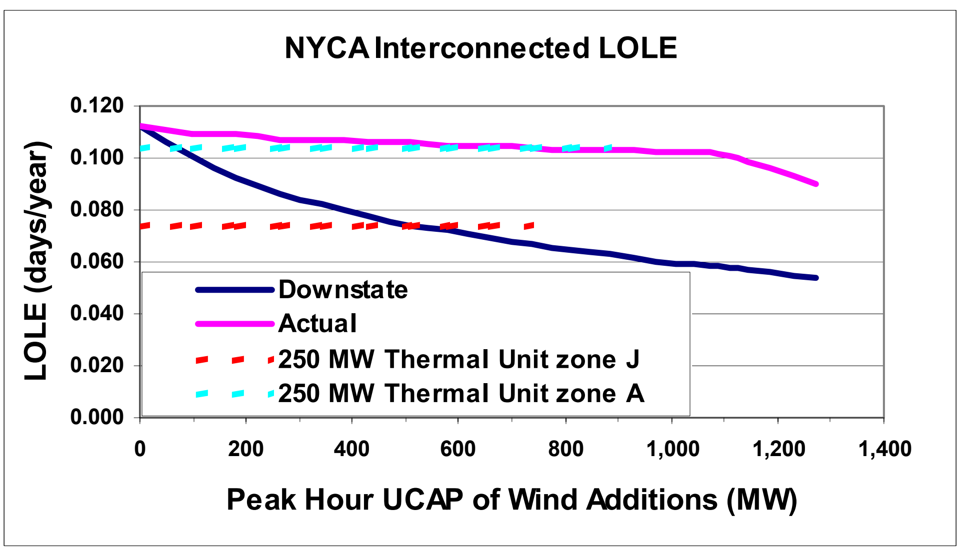

Figure 5.13 NYCA LOLE vs. Peak-Hour UCAP including Thermal Unit

The reliability of a system varies exponentially with reserve margins. Therefore most of the risk of outages will occur during the top 10% of the load. As an additional test, we limited the capacity factor determination to only those hours in the year when the load was at least 90% of the NYCA system peak. During these hours the average capacity factor for all of the wind plants was only 7%. In these circumstances the modified UCAP for all wind plants up through Group F is 238MW, which is approximately the same as the reliability value of the 250MW thermal unit, which produced the same reliability impact.

5.4.3 Impact of shifting daily wind patterns.

One further refinement involves the treatment of the daily wind patterns. As was stated earlier, the wind generation was treated as firm capacity that varied on an hourly basis. However, as shown in Figure 5.10 and Figure 5.11, the daily patterns were highly variable. We might inadvertently penalize the reliability value of a unit because the pattern predicted zero output on the peak day. Or conversely the timing of the system peak might have been aligned with a particularly windy day. Figure 5.14 shows the impact of shifting the daily wind patterns by one to seven days for one of the downstate wind cases. For each daily shift the 8760 chronological outputs of the wind plants was advanced by 24 hours. While the system LOLE did not drastically shift there was some variation in the results. Figure 5.15 shows this impact on the curve of NYCA LOLE versus ICAP of wind additions.

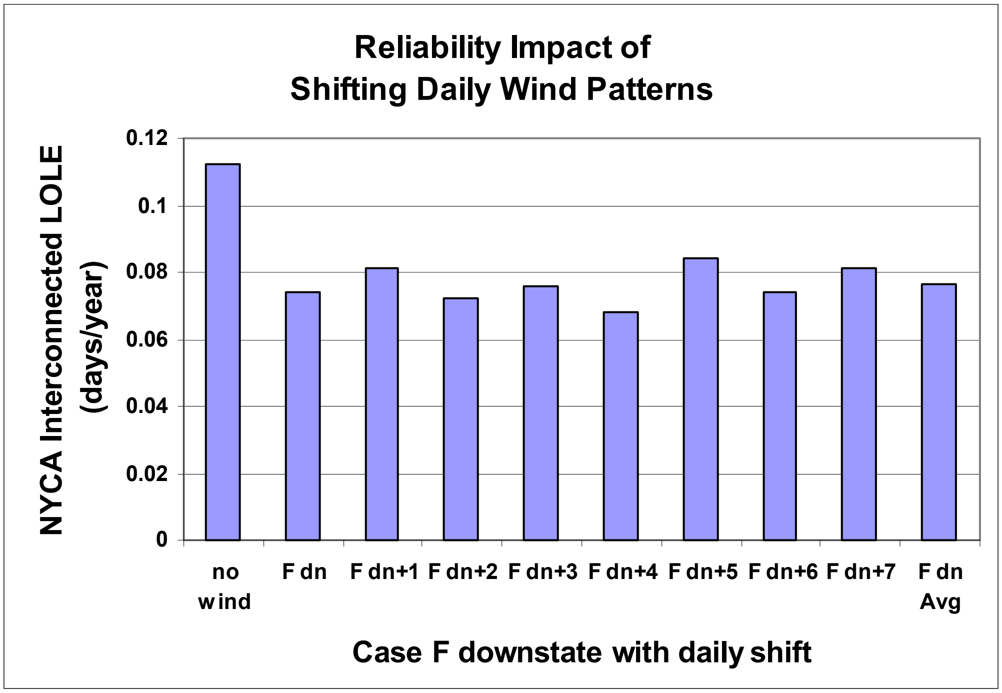

Figure 5.14 Impact of shifting daily wind patterns

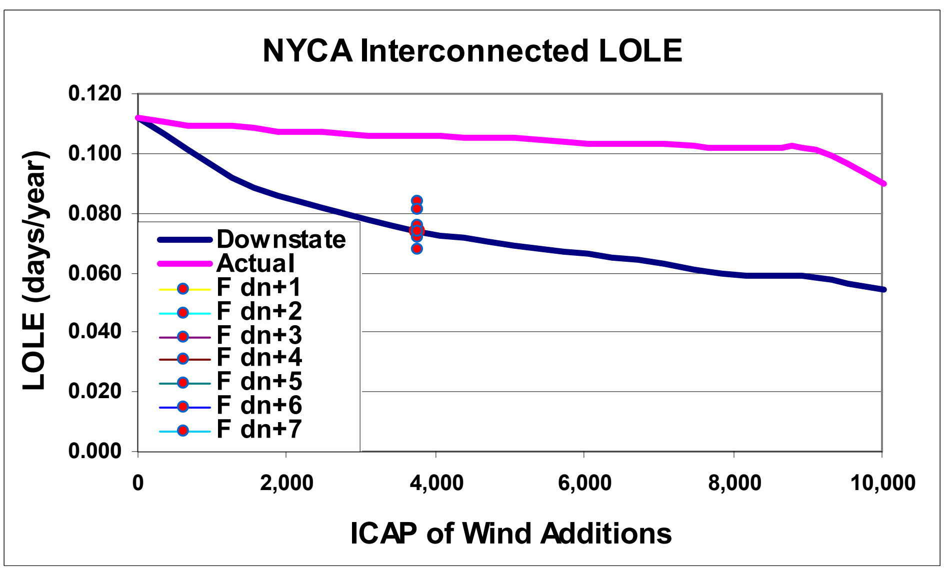

Figure 5.15 Impact on NYCA Interconnected LOLE of shifting daily wind patterns.

5.5 SUMMARY

This analysis examined the impact of progressively increasing levels of wind turbine additions on the interconnected reliability of the NYCA as measured by Loss of Load Expectation, LOLE. While their average capacity factors were about 30% the capacity values based on their intermittent generation characteristics was only about 10% of their nameplate ratings.

Wind turbines demonstrate definite seasonal and diurnal output characteristics and the existing UCAP calculations should be modified to reflect that fact. Wind generation patterns within New York State demonstrate much lower levels of output in the summertime (Figure 5.16), and within the day they tend to peak in the morning, with afternoon and evening outputs roughly half of the morning levels (Figure 5.17). This provides little reliability value to a system that typically experiences its greatest need for capacity in late afternoon and early evening in the summer. A modification of the UCAP calculations based on the expected capacity factor during peak intervals provides UCAP values much more in line with actual reliability impacts.

Due to the current generation and transmission configuration within New York, additional capacity added west of the Central East Interface provides only a fraction of the reliability value as compared to capacity added downstate. Since location is not a factor when evaluating the UCAP of conventional generation it should not be used to penalize wind. However, it is something that needs to be kept in mind since 85% of the potential sites identified in this analysis fall west of this interface.

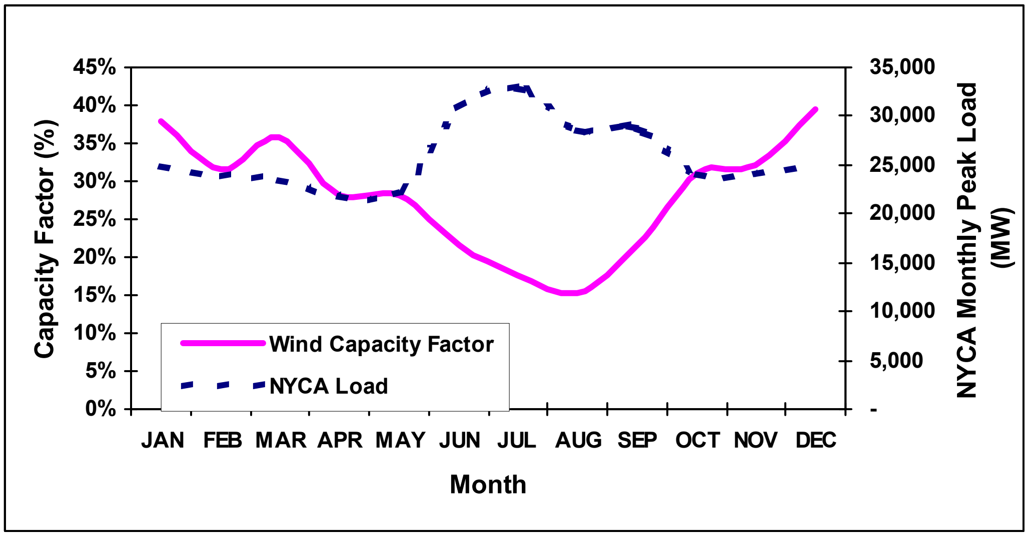

Figure 5.16 Average monthly capacity factor for all 101 wind sites and NYCA monthly peak load

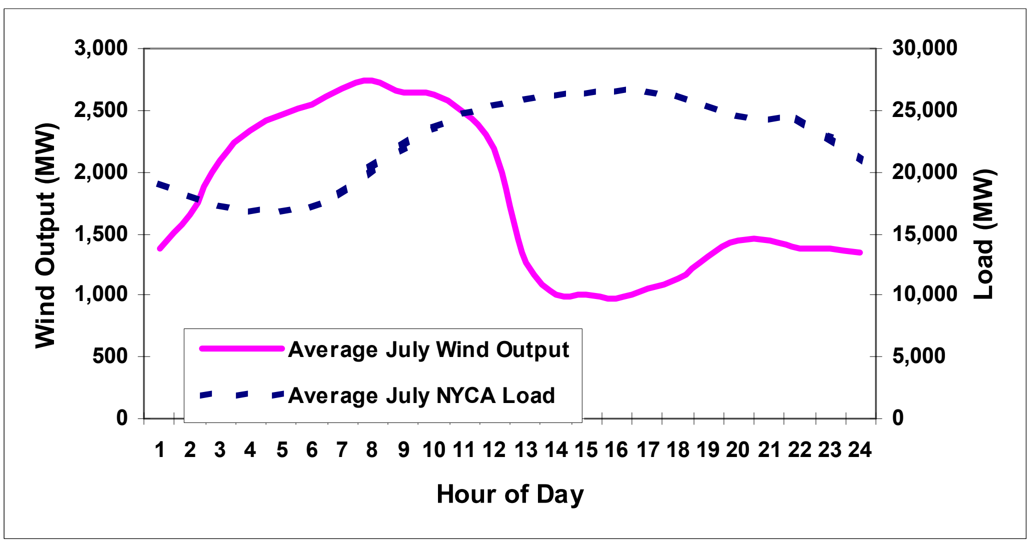

Figure 5.17 Average hourly output for all 101 wind sites and NYCA average load for July

Although it may provide minimal benefit, the addition of wind generation, in and of itself, will not cause the reliability of the system, as measured by LOLE, to degrade. However, if existing, marginally operating, thermal generation is retired, or if expected new generation is deferred or cancelled as a result of wind additions then system reliability will be negatively impacted, although the NPCC minimum reliability threshold of 0.1 days/year LOLE will always be maintained. Phase II of this analysis will examine more of the operational impacts of wind generation, including the impact on spinning reserve, unit commitment and the change in cycling duty and capacity factors of thermal generation.

6. PLANNING AND OPERATION CRITERIA

6.1 INTRODUCTION

The objective of this task of the Preliminary Overall Reliability Assessment is to review relevant North-American Electric Reliability Council (NERC), Northeast Power Coordinating Council (NPCC), New York State Reliability Council (NYSRC), and New York Independent System Operator (NYISO) reliability rules for planning and operation of the New York State Bulk Power System (NYSBPS), identify those rules that may be impacted by large-scale wind generation additions to the New York State power system, and make recommendations for changes or additions to those planning and operating rules in order to properly account for the presence of significant wind generation in New York State.

Given the large number of documents that address the reliability, planning and operation of the NYSBPS, and the limited time available to perform this preliminary assessment, the choice of documents identified for review at this stage was made in consultation with NYISO personnel who are familiar with the reliability rules applicable in New York State. The documents that were identified and reviewed in this preliminary phase of the project are listed in Table 6.1 below, and include NERC, NPCC, NYSRC and NYISO documents for system planning and operation.

Table 6.1 Documents reviewed for Reliability Rules impact assessment

NYISO	System Operation Procedures
NYISO	Installed Capacity Manual (ICAP)
NERC	Planning Standards
NERC	Operating Manual
NPCC	Basic Criteria for Design and Operation of Interconnected Power Systems
NPCC	Operating Reserve Criteria
NPCC	Guide for Rating Generating Capacity
NYSRC	Reliability Rules

The primary mission of NERC is to ensure the bulk electric power system in North America is operated in a reliable, adequate and secure manner. NERC accomplishes this mission, in part, by setting and enforcing standards for the reliable planning and operation of the bulk power system. The NERC standards are applicable to the whole of North America and, as a result, tend to be general in nature to allow a level of flexibility for implementation in regions with different characteristics and reliability needs. At the regional level, the Regional Reliability Councils establish their own planning and operation criteria that are tailored to the needs of their own regions, consistent with the planning and operation standards specified by NERC. NPCC is the regional reliability council with oversight authority over the State power system, and its reliability standards are a variation of the standards set by NERC for the Northeast region.

In New York State, NYSRC is the responsible authority for the development and maintenance of reliability rules for the planning and operation of the State power system. The NYSRC reliability rules are written in accordance with the NERC and NPCC rules and criteria, and incorporate New York statewide and local rules that recognize the unique characteristics and reliability needs of the State and its various zones. As such, the NYSRC reliability rules are more specific to New York State reliability needs and, in general, are more stringent than their NERC and NPCC counterparts. For that reason, the impact of significant wind penetration on the reliability rules governing the planning and operation of the State power system will be discussed in terms of any impact on the NYSRC reliability rules, with references to specific NERC and NPCC rules and criteria made only when appropriate. A detailed description of the NYSRC reliability rules can be found in the document "*NYSRC Reliability Rules for Planning and Operating the New York State Power System*" available at http://www.nysrc.org/documents.html.

As mentioned earlier, Phase 1 of this study is a preliminary evaluation that will be followed by a more detailed system impact study in Phase 2, and the conclusions of both Phase 1 and Phase 2 work will determine the ultimate impact of significant wind penetration on the rules governing the planning and operation of the New York State power system. In Phase 2 of the study, the subject of planning and operation practices will be revisited and the impact on the reliability rules will be examined in light of the complete findings of the study.

6.2 IMPACT ON THE NYSRC RELIABILITY RULES

The NYSRC reliability rules, outlined in the document "*NYSRC Reliability Rules for Planning and Operating the New York State Power System,*" define reliability of the State power system in terms of resource adequacy and system security as follows:

- Adequacy – The ability of the electric systems to supply the aggregate electrical demand and energy requirements of their customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements
- Security – The ability of the electric systems to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements

These rules describe the system planning and operation criteria used to achieve adequacy and security, and are grouped in eleven rule groups covering the following areas:

- Resource adequacy
- Transmission capability - planning
- Resource, system and demand data requirements
- Operating reserves
- Transmission capability - operating
- Operation during major emergencies
- System restoration
- System protection
- Local reliability rules
- NYISO control center communications
- Reliability assessment

A review of the NYSRC reliability rules shows that the statement of these rules is focused on the definition of system operation and performance requirements necessary to achieve the desired level of system reliability, and on the responsibility of the various market participants for ensuring compliance with the rules. The rules, as stated, refer to generation resources and their adequacy in terms of their capacity with no distinction between the different types of generation, (wind, thermal, hydro, or other forms). Consequently, the text of the reliability rules remains valid regardless of the generation mix and the percentage of that mix that is derived from wind. What is affected by a significant penetration of wind generation, however, are the rules for quantifying the capacity value of wind generation, the setting of reserve requirements and some of the planning and performance criteria definitions that are referenced in the rules. For example, the first rule in the resource adequacy group states the following:

> *"Adequate resource capacity shall exist in the NYCA such that, after due allowance for scheduled outages and deratings, forced outages and deratings, assistance from neighboring systems, New York State Transmission System transfer capability, uncertainty of load forecasts, and capacity and/or load relief from available operating procedures, the probability of disconnecting firm load due to a resource deficiency will be, on the average, no more than once in ten (10) years."*

This criterion is also referred to as a Loss Of Load Expectation (LOLE) of one day in ten years, or 0.1 days per year. The statement of this rule describes a planning/operation guideline for procuring adequate generation capacity to meet the load, and is valid regardless of the type of generation used. However, the method for calculating the capacity value of generation resources will require modifications to properly reflect the capacity value of wind generation.

In the following subsections, each of the NYSRC reliability rule groups is briefly described, and comments as to the impact of significant wind generation on the validity of the rule is given. References to other documents that should be re-examined to properly account for the presence of significant wind generation are also included as applicable.

6.2.1 Resource adequacy

The objective of this rule group is to establish guidelines and responsibilities for providing adequate generation resources to the New York Control Area (NYCA). Determination of adequate resources includes consideration of such factors as load uncertainty, resource outages, transmission constraints and interconnections to other control areas.

The language of this rule is not specific to the type of generation used and is not affected by the presence of significant wind generation. However, the procedures used to evaluate the capacity value of generation resources should be re-examined and updated to properly reflect the capacity value of wind generation. Specifically, Attachment J, "Unforced Capacity for Installed Capacity Suppliers," of the NYISO "Installed Capacity Manual" should be re-examined and updated to reflect the conclusions of the "Reliability Analysis" of this study in the evaluation of wind generation Unforced Capacity (UCAP) value. Also, Section 4.8.6, "Intermittent Power Resources" of the same manual, and the references therein, addressing daily bidding and scheduling requirements for intermittent resources should be re-examined and possibly updated to account for the impact significant wind generation could have on the scheduling and adequacy of scheduled resources.

Review of NERC and NPCC documents pertaining to this subject revealed no additional issues related to resource adequacy.

6.2.2 Transmission capability – planning

This rule group establishes guidelines for the planning of sufficient transmission resources to ensure the system ability to withstand design criteria contingencies without significant disruption to system operation. Both power flow conditions and design contingencies are significant components of the planning process.

According to the NPCC Document A-2 "Basic Criteria for Design and Operation of Interconnected Power Systems," design studies should assume power flow conditions with applicable transfers, load and generation conditions that stress the system. It may be necessary to include in these study conditions various levels of wind generation to appropriately bracket system response.

Design criteria contingencies that should be considered in transmission system planning are listed in Table A of the rule text, and include the loss of any critical generator, transmission circuit, transformer, series or shunt compensating device, or high voltage direct current (HVDC) terminal. This is what is referred to in the industry as the “N-1” reliability planning rule. The rule also requires assessment of the impact of extreme contingencies on system performance, and provides a listing of extreme contingencies that should be considered in Table B of the rule text. The guidelines are discussed in terms of thermal, voltage, and stability criteria.

This rule requires that the system be able to withstand the loss of any critical generator without major disruption to system operation. However, with the presence of significant wind generation the definition of a “critical generator” may have to be re-considered. Wind resources in New York State tend to be clustered in the central and western regions of the state, where they could all be vulnerable to the same weather conditions that could result in the loss of all wind generation in those regions within an as yet indeterminate period of time. As noted above, this event could be incorporated in the generation dispatch of a particular study condition or possibly considered as a “critical generator” loss contingency. In Phase 2 of the study, the operating characteristics of wind generation, specifically the magnitude and rate of change in power output, and how it impacts this rule will be examined in greater detail.

Section 5.0 of the NPCC “Bulk Power System - Transmission Design Criteria” document, and Section IA of the “NERC Planning Standards” document refer to the critical generator loss contingency, and may also need to be modified to include contingencies for the loss of all wind generation in specific regions.

6.2.3 Resource, system and demand data requirements

This rule group establishes the requirements for the development and submission by market participants of system data for the purpose of system modeling and simulation. The system modeling data required by this rule includes resource capacity verification testing, resource availability, system data, and load forecasting.

The language of the NYSRC rules in this group is generic and is not affected by the type of generation resources used. However, some of the procedures used for resource capacity verification and resource availability may have to be modified or expanded to address the special characteristics of wind generation. Specifically, Section 4.2.2, "Resource Specific Test Conditions," of the NYISO "Installed Capacity Manual" should be expanded to include specific test requirements applicable to wind resources for the measurement of their Dependable Maximum Net Capacity (DMNC). Section 2.2, "Guidelines – Individual Unit Types," of the NPCC "Guide for Rating Generating Capacity" should also be expanded for the same reason. Although, no specific requirements for the software tools used for load flow, short-circuit, and stability calculations were included in any of the reviewed documents, these tools must be updated to properly model the characteristics of the different wind generation technologies in order to meet the requirements of this reliability rule.

Review of NERC documents pertaining to this subject revealed no additional issues related to resource, system and data requirements.

6.2.4 Operating reserves

This rule group establishes the minimum requirements for operating reserves in the NYCA. The factors considered in the evaluation of operating reserve requirements include unexpected resource and transmission contingencies, regulation of frequency and tie line flow, and load forecast error. The rules cover the following areas:

- Operating Resource Adequacy
- Minimum Operating Reserve Requirement
- Availability and Category of Reserves

The language of the rules in this group is general and unaffected by the type of generation used, however, the mechanics for ensuring compliance with the spirit of these rules may have to be re-examined. Specifically, operating reserve requirements and the category of reserves may have to change depending on the level of wind generation in the generation mix at any given time. The same comments made about this also apply to the NERC and NPCC documents that address the subject of operating reserves.

The ten-minute and thirty-minute operating reserve requirements are normally set to cover the loss of any critical generator in the system, and may also have to consider the potential loss of wind generation in a given geographical area due to adverse weather conditions. The ten-minute reserves are normally split between synchronized reserves, and non-synchronized reserves that could be made available to serve load within ten minutes. The synchronized reserves are intended for load following, frequency regulation and tie line flow regulation, and may have to be increased to account for the variability of wind generation output. This variability is illustrated in Figure 6.1 and Figure 6.2. Figure 6.1 shows the total hourly output projected for the 101 sites being considered in this study, and Figure 6.2 shows the hourly change in output from one hour to the next. As these curves show, there can be significant hourly swings in the output of wind generation, where some of these swings exceed the current ten-minute and thirty-minute operating reserves. Whether or not a change to the operating reserve criteria becomes necessary will depend on the findings of Phase 2 of this study, where the magnitude and rate of change of expected wind generation fluctuations will be analyzed in greater detail.

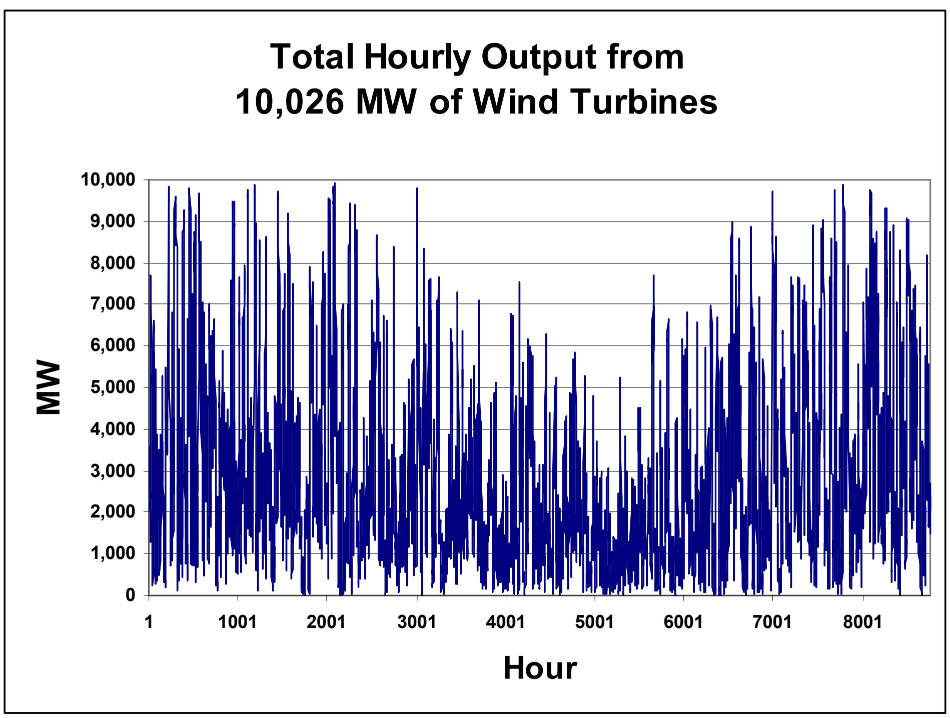

Figure 6.1 Total projected hourly output for the 101 wind generation sites considered in this study

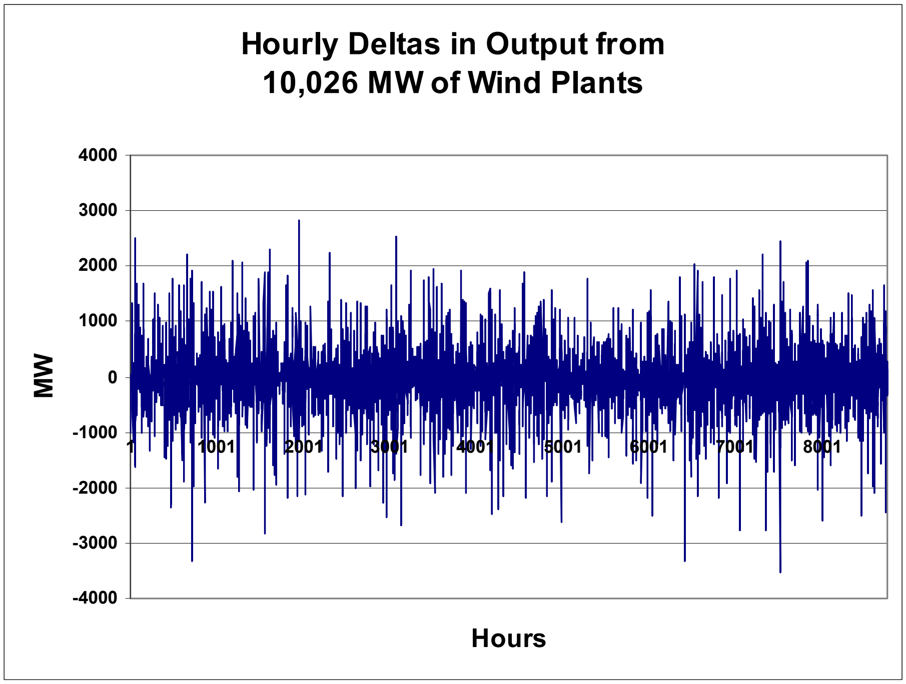

Figure 6.2 Hourly change in total wind output from the previous hour

6.2.5 Transmission capability - operating

This rule group establishes guidelines for transmission system operation in order to withstand the design criteria contingencies specified in the Transmission Capability – Planning rule, without adversely affecting the reliability of the NYSBPS or neighboring systems. The operating rules are discussed in terms of the following criteria:

- Thermal Assessment
- Voltage Assessment
- Stability Assessment
- Post-Contingency Operation
- Outage Coordination
- Operation During Impending Severe Weather
- Operation During a Severe Solar Magnetic Disturbance
- Fault Current Assessment

The language of the rules in this group is not specific to the type of generation used, and is unaffected by the presence of significant wind generation in the generation mix. One exception to this relates to the rule on operation during impending severe weather. This rule may need to be modified to direct system operators to schedule additional generation reserves or other resources to deal with potential loss of wind generation in regions threatened by severe weather conditions.

The NYISO "System Operating Procedures" manual also contains references to adverse weather conditions in the description of all system operating states and system conditions. This document should be reviewed in more detail and possibly modified to include instructions to operators to schedule additional necessary reserves to deal with these weather conditions.

Review of NERC and NPCC documents pertaining to this subject revealed no additional issues related to transmission system operation.

It is important to note that while the output of wind turbines generally increases with increased wind speeds, the turbines have a "cut-out" speed at which they shut down in order to protect the equipment. Therefore, it is not unlikely for a wind plant output to increase with the advent of a storm only to shut down from maximum output once the storm arrives and wind speed rises above cut-off speed.

6.2.6 Operation during major emergencies

This rule group establishes the guidelines for operation during emergency conditions. The language of this rule is general and is not affected by the type of generation used, including wind. Review of NERC and NPCC documents pertaining to this subject revealed no additional issues related to operation during major emergencies

6.2.7 System restoration

This rule group establishes the rules for restoring the system after a partial or system-wide shutdown. Again, the language of this rule is general and not affected by the type of generation used. Review of NERC and NPCC documents pertaining to this subject revealed no additional issues related to system restoration.

6.2.8 System protection

This rule group sets the rules for protection of the NYSBPS. The protection systems covered by this rule include:

- Bulk Power System Protection
- Power System Protection Maintenance

The language of this rule, and the NPCC rules it references in the NPCC "Bulk Power System Protection Criteria" and the NPCC "Maintenance Criteria for Bulk Power System Protection" is general and not affected by the type of generation used. The corresponding NERC documents revealed no additional issues related to system protection.

6.2.9 Local reliability rules

This rule group sets the local reliability rules that apply to the New York City and the Long Island zones. The rule addresses the following issues:

- Operating Reserves/Unit Commitment (New York City)
- Locational Reserves (New York City)
- Loss of Generator Gas Supply (New York City & Long Island)
- Thunderstorm Watch (New York City)

These are operating rules, but there are also locational requirements on installed capacity for New York City and Long Island to satisfy the resource adequacy requirements discussed in Section 6.2.1. The language of the rule, however, is general and not affected by the type of generation used. There are no corresponding NERC and NPCC addressing this issue.

6.2.10 NYISO control center communications

This rule group establishes the guidelines for data and voice communication between the NYISO and market participants under normal and emergency system conditions. These rules are unaffected by the presence of wind generation, and neither are their NERC and NPCC counterparts.

6.2.11 Reliability assessment

This rule group establishes the mechanism by which NYSRC ensures that the NYISO planning and operation manuals are in compliance with the reliability rules. The rules in this group are not affected by the presence of wind, and neither are their NERC and NPCC counterparts.

6.3 SUMMARY

This review of the reliability rules for the planning and operation of the NYSBPS shows that while, in general, the rules as written do not need to be modified to account for the presence of significant wind generation in the state, some of the procedures and the planning and performance criteria definitions referenced in the rules may have to be examined and possibly modified. Specifically, the following procedures may need to be modified:

- Calculation of operating reserves, regulation and load following requirements in the presence of wind generation
- Calculation of unforced capacity value of wind generation
- Consideration of wind generation in transmission planning
- Test requirements for the Dependable Maximum Net Capacity (DMNC) measurement of wind generation
- Operating procedures for operation with impending severe weather conditions

From an operational standpoint, it is not essential to update any of these procedures immediately in order to proceed with the integration of new wind generation projects in the State. However, all of these procedures will need to be updated before significant wind penetration levels are achieved.

Some procedures may need to be updated sooner than others in order to facilitate the planning of the system. For instance, the procedure for calculating the UCAP for wind generators will need to be updated before capacity credits can be issued to wind generators. This will also be critical to wind developers, as capacity payments are a factor in determining the economic feasibility of prospective wind projects. Also, operating procedures with severe weather conditions and the rules for calculating operating reserves, regulation and load following requirements will need to be updated.

Again, this is a preliminary review that will be revisited in Phase 2 of the study, where the evaluation will be made in light of the complete findings of the study.

Appendix A. New York State Power System Interface Definitions

Interface	Definition
ON-NY	81256 STLAWL33-79589 MOSES E 230kV 81255 STLAWL34-79589 MOSES E 230kV 81508 BECK B-79584 NIAG 345 345kV 81509 BECK A-79584 NIAG 345 345kV 81515 BP76 REG-PACKARD2 230kV 81516 PA27 REG-NIAGAR2W 230kV
NE-NY	73117 CTNY398-74344 PLTVLLEY 345kV 73166 NORHR138-75053 NRTHPT P 138kV 72928 MANY393-78700 ALPS345 345kV 72385 BRSWAMP-78980 ROTRDM.2 230kV 70522 BNNINGTN-79135 HOOSICK 115kV 70525 BLISSVIL-79167 WHITEHAL 115kV 70511 GRAND IS-79602 PLAT T#3 115kV
PJM-NY	23 WESCOVLE-1 ALBURTIS 500kV 9 JUNIATA-1 ALBURTIS 500kV 16 3 MILE I-90 A25 500kV 13 PEACHBTM-24 LIMERICK 500kV 13 PEACHBTM-9806 A29 COLL 500kV 11 KEYSTONE-9 JUNIATA 500kV 5 CONEM-GH-9 JUNIATA 500kV 4 CNASTONE-13 PEACHBTM 500kV 5 CONEM-GH-26 HUNTERTN 500kV 05 01DOUBS-3 BRIGHTON 500kV
West-Central	75417 STOLE230-5414 MEYER230 230kV 76510 ANDOVER1-5994 PALMT115 115kV 77111 MORTIMER-7110 LAWLER-1 115kV 77111 MORTIMER-7463 LAWLER-2 115kV 77400 CLAY-9801 PANNELL3 345kV 77400 CLAY-9801 PANNELL3 345kV 79805 CLYDE199-5893 SLEIG115 115kV 79805 CLYDE199-7433 CLTNCORN 115kV 79810 STA 162-5995 S.PER115 115kV 79825 PANNELLI-7447 FRMGTN-4 115kV 79826 QUAKER-5892 MACDN115 115kV 79826 QUAKER-9804 S121 B#2 115kV 79875 FARMNGTN-7444 FARMGTN1 115kV 79875 FARMNGTN-77447 FRMGTN-4 115kV 79946 S168-77447 FRMGTN-4 12kV/115kV
Central East	79583 MARCY T1-78703 N.SCOT99 345kV 78450 EDIC-78702 N.SCOT77 345kV 78460 PORTER 2-78980 ROTRDM.2 230kV "1" 78460 PORTER 2-78980 ROTRDM.2 230kV "2" 78478 INGMS-CD-79136 INGHAM-E 115kV 75447 E.SPR115-79136 INGHAM-E 115kV 79602 PLAT T#3-70511 GRAND IS 115kV

Interface	Definition
Total East	75512 W.WDB115-76210 W.WDBR69 115kV/69kV 75403 FRASR345-79581 GILB 345 345kV 75400 COOPC345-79304 SHOEMTAP 345kV 75400 COOPC345-75420 CALPINE 345kV 2 BRANCHBG-74300 RAMAPO 5 500kV 4989 HUDSON1-74328 FARRGUT1 345kV 5039 HUDSON2-74329 FARRGUT2 345kV 4996 LINDEN-74371 GOETHALS 230kV 5028 WALDWICK-79302 SMAHWAH1 345kV 5028 WALDWICK-79303 SMAHWAH2 345kV 75447 E.SPR115-79136 INGHAM-E 115kV 78450 EDIC-78702 N.SCOT77 345kV 78460 PORTER 2-78980 ROTRDM.2 230kV "1" 78460 PORTER 2-78980 ROTRDM.2 230kV "2" 78478 INGMS-CD-79136 INGHAM-E 115kV 79583 MARCY T1-78703 N.SCOT99 345kV 79602 PLAT T#3-70511 GRAND IS 115kV
UPNY-SENY Closed	2 BRANCHBG-74300 RAMAPO 5 500kV 73117 CTNY398-74344 PLTVLLEY 345kV 75400 COOPC345-75420 CALPINE 345kV 75400 COOPC345-79304 SHOEMTAP 345kV 75512 W.WDB115-76210 W.WDBR69 115kV/69kV 78701 LEEDS 3-74000 HURLEY 3 345kV 78701 LEEDS 3-78705 ATHENS 345kV 78701 LEEDS 3-74344 PLTVLLEY 345kV 78705 ATHENS-74344 PLTVLLEY 345kV 78730 ADM-74043 PL.VAL 1 115kV 78739 BL STR E-74043 PL.VAL 1 115kV 78742 BLUES-8-74043 PL.VAL 1 115kV 78757 BOC 2T-74040 N.CAT. 1 115kV 4989 HUDSON1-74328 FARRGUT1 345kV 4996 LINDEN-74371 GOETHALS 230kV 5028 WALDWICK-79302 SMAHWAH1 345kV 5028 WALDWICK-79303 SMAHWAH2 345kV 5039 HUDSON2-74329 FARRGUT2 345kV 73166 NORHR138-75053 NRTHPT P 138kV
UPNY-ConEd Closed	74002 ROSETON-74331 FISHKILL 345kV 74026 FISHKILL-75762 SYLVN115 115kV 74022 E FISH I-74331 FISHKILL 115kV/345kV 74340 LADENTWN-74313 BUCH S 345kV 74344 PLTVLLEY-74331 FISHKILL 345kV 74344 PLTVLLEY-74331 FISHKILL 345kV 74344 PLTVLLEY-74341 MILLWOOD 345kV 74344 PLTVLLEY-74356 WOOD B 345kV 74347 RAMAPO-74312 BUCH N 345kV 4989 HUDSON-74328 FARRGUT1 345kV 5039 HUDSON2-74329 FARRGUT2 345kV 4996 LINDEN-74371 GOETHALS 230kV 73166 NORHR138-75053 NRTHPT P 138kV

Interface	Definition
ConEd Cable	4989 HUDSON1-74328 FARRGUT1 345kV 4996 LINDEN-74371 GOETHALS 230kV 5039 HUDSON2-74329 FARRGUT2 345kV 74316 DUNWODIE-74650 REAC71 345kV 74316 DUNWODIE- 74651 REAC72 345kV 74348 SPRBROOK-74351 TREMONT 345kV 74348 SPRBROOK-74567 REACM51 345kV 74348 SPRBROOK-74568 REACM52 345kV 74420 DUN NO1R-74533 S CREEK 138kV 74421 DUN NO2R-74533 S CREEK 138kV 74424 DUN SO1R-74435 E179 ST 138kV 75047 L SUCSPH-74505 JAMAICA 138kV 75067 V STRM P-74505 JAMAICA 138kV
LIPA	74316 DUNWODIE-75000 SHORE RD 345kV 75047 L SUCSPH-74505 JAMAICA 138kV 75067 V STRM P-74505 JAMAICA 138kV 73166 NORHR138-75053 NRTHPT P 138kV 74349 REACBUS-79607 DVNPT NK 345kV

Appendix B. Fatal Flaw Analysis Results Spreadsheets

Local Contingency Analysis Results for Addition of Wind Generation to 80% Peak Load System

AWS Data		*Power Flow Data*				*Redispatch*			*Pre-Contingency*				*Post-Contingency*							
RANK	ZONE	kV	Area #	MW	Running Sum	Δ	Units	Area	Overloaded Element	MVA Rating	OL (pu)	Revised MW	Overloaded Element	MVA Rating	OL (pu)	Contingency	Q wind (MVAr)	Voltage (pu)	Revised MW	Running Sum
1	E	345	6	60.5	61		78731 JMC1+7TP	6				60.5					-3.7	1.04	60.5	61
2	B	115	3	49.9	110		75963 GRNIDG 3	3				49.9					-13.9	1.03	49.9	110
3	E	115	5	49.9	160		78012 CLIMAX, 78022 FT. DRUM	5				49.9					-9.9	1.03	49.9	160
4	F	115	5	49.9	210		78022 FT. DRUM, 79305 CALPGT1	5				49.9					-12.1	1.01	49.9	210
5	A	115	1	72.5	283		76802 OXBOWNUG, 76642 DUNK115G	1				72.5					27	1.05	72.5	283
6	E	115 230	5	400.0	683	683	79305 CALPGT1, 79306 CALPGT2, 79307 CALPST1	5	LOWVILLE-BOONVL 115 kV	106	1.16	362.7	LOWVILLE-TAYLORVL 115 kV	114	1.012	LOWVILLE-BOONVL 115kV	-30.1	1.01	352.7	635
7	A	230	1	77.7	760		76642 DUNK115G, 76642 DUNK115G	1				77.7					-38.2	1.00	77.7	713
8	D	230	4	181.5	942		76483 NOEND3S$, 76482 NOEND2G$, 76481 NOEND1G$	4				181.5					-15	1.05	181.5	895
9	A	230	1	172.3	1114		76642 DUNK115G, 76641 DUNKGEN4, 76641 DUNKGEN4	1				172.3					-31.2	1.03	172.3	1067
10	D	230	4	141.1	1255	573	76481 NOEND1G$, 79515 MOS19-20, 79515 MOS19-20	4				141.1					-11.6	1.05	141.1	1208
11	G	345	6	49.9	1305		78731 JMC1+7TP, 79289 INDECK-C	6				49.9					10.1	1.04	49.9	1258
12	A	345	1	89.3	1395		76641 DUNKGEN4	1				89.3					-38.2	1.04	89.3	1347
13	E	115	3	68.2	1463		75963 GRNIDG 3, 75755 GOUDEY 8	3				68.2					-9	1.02	68.2	1415
14	A	230	1	109.5	1572		76641 DUNKGEN4, 76640 DUNKGEN3, 76640 DUNKGEN3	1				109.5					-10.8	1.03	109.5	1525
15	F	345	6	49.9	1622		79289 INDECK-C, 78709 ATHENSS2	6				49.9					3.8	1.04	49.9	1575
16	E	115	5	89.6	1712		79307 CALPST1	5	LOWVILLE-BOONVL 115 kV	106	1.07	39.6					5.4	1.03	39.6	1614
17	A	345	1	74.2	1786		76640 DUNKGEN3	1				74.2					-18.2	1.04	74.2	1689
18	A	230	1	88.7	1875	619	76640 DUNKGEN3, 77051 HNTLY68G, 77051 HNTLY68G	1				88.7					-7.9	1.00	88.7	1777
19	A	345	1	253.4	2128		77051 HNTLY68G, 77050 HNTLY67G, 77050 HNTLY67G, 75523 KINTIG24	1				253.4					-25.3	1.04	253.4	2031
20	A	115	1	133.5	2262		75523 KINTIG24	1				133.5					86.2	1.05	133.5	2164
21	A	115	1	159.2	2421		75523 KINTIG24	1	SLVRC115-DUNKIRK1 115 kV	88	1.15	136.2	SLVRC115-DUNKIRK1 115 kV	101	1.42	SLVRC115-NANG-141 115kV	-34.3	1.03	93.8	2258
22	E	115	5	55.9	2477	602	79307 CALPST1	5	LOWVILLE-BOONVL 115 kV	106	1.07	5.9					-0.1	1.04	5.9	2264
23	A	115	2	181.9	2658		79943 RUS 3G, 79944 RUS 4G, 77121 SENECAP	2	BATAVIA1-OAKFLDTP 115 kV	128	1.12	156.6	BATAVIA1-OAKFLDTP 115 kV	136	1.07	OAKFLDTP-OAKFIELD 34.5kV	-18.3	1.02	136.6	2401
24	A	115	2	172.3	2831		77121 SENECAP, 79940 GINNA 19	2	BRCKPTHS-SWDN-111 115 kV	76	1.74	89.5	MORTIMER-SWDN-111 115 kV	136	1.02	BRCKPTHS-BRCKPT13 13.2kV	-2.7	0.99	79.5	2480
25	A	115	2	197.3	3028		79940 GINNA 19	2	BRCKPTHS-SWDN-111 115 kV	76	2.94	4.9					-0.2	0.99	4.9	2485
26	B	115	2	73.5	3102	625	79940 GINNA 19	2				73.5					-5.3	1.03	73.5	2558
27	D	115	4	49.9	3152		79515 MOS19-20, 79516 MOS21-22	4				49.9					-8.6	1.04	49.9	2608
28	A	230	1	67.2	3219		75523 KINTIG24	1				67.2					-0.4	1.00	67.2	2676
29	B	115	2	61.5	3280		79940 GINNA 19	2				61.5					-4.7	1.03	61.5	2737
30	D	230	4	60.4	3341		79516 MOS21-22, 79516 MOS21-22	4				60.4					6.5	1.06	60.4	2797
31	C	115	3	108.0	3449		75755 GOUDEY 8, 75964 GRNIDG 4	3				108	EELPO115-MEYER115 115 kV	128	1.04	EELPO115-FLATS115 115kV	-7.1	1.03	98.0	2895
32	A	115	2	73.3	3522		79940 GINNA 19	2	LAPPINS1-NLEROYTA 115 kV	139	1.07	23.3	MORTIMER-SWDN-111 115 kV	136	1.03	BATAVIA1-SENECAP 115kV	NA	NA	0	2895
33	E	230	5	91.8	3614		79307 CALPST1	5				60.2					53.1	1.02	60.2	2956
34	C	230	3	50.1	3664		75964 GRNIDG 4	3				50.1	MEYER115-S.PER115 115 kV	96	1.08	MEYER230-STOLE230 230kV	NA	NA	0	2956
35	A	230	1	88.8	3753	651	75523 KINTIG24	1				88.8					-2	1.03	88.8	3044
36	F	345	6	49.9	3803		78709 ATHENSS2	6	CURRY RD-RTRDM1 115 kV	120	1.07	0					NA	NA	0	3044
37	A	115	1	67.7	3870		75523 KINTIG24	1				67.7					41.2	1.01	67.7	3112
38	A	115	1	68.6	3939		75523 KINTIG24	1				68.6					-23.7	1.00	68.6	3181
39	F	345	6	61.4	4000		78709 ATHENSS2	6				61.4	CURRY RD-RTRDM1 115 kV	116	1.00	N.SCOT99-MARCY T1 345kV	NA	NA	0	3181
40	C	115	3	67.7	4068		75964 GRNIDG 4	3	FLATS115-GRNDG115 115 kV	108	1.06	47.7	EELPO115-MEYER115 115 kV	128	1.31	EELPO115-FLATS115 115kV	NA	NA	0	3181
41	E	115	5	52.3	4120		No further redispatch available	5				0					NA	NA	0	3181
42	E	115	4	49.9	4170		79516 MOS21-22, 79518 MOS25-26	4				49.9					-15.7	1.05	49.9	3231
43	E	115	5	82.6	4253		No further redispatch available	5				0					NA	NA	0	3231
44	A	115	1	82.1	4335		75523 KINTIG24, 76296 LEA 1G $, 76297 LEA 2G $	1				82.1					-24.4	1.00	82.1	3313
45	C	115	3	51.8	4387		75964 GRNIDG 4, 76112 MILKN 1	3				51.8					2.3	1.01	51.8	3365
46	C	230	3	58.6	4445		Maximum generation at this bus already	3				0					NA	NA	0	3365
47	A	345	1	150.2	4595	649	76297 LEA 2G $, 76298 LEA 3G $, 76299 LEA 4S $, 76548 INDEK-OL	1				150.2					-45.4	1.04	150.2	3515
48	C	115	3	73.9	4669		76112 MILKN 1	3				73.9					11.9	1.05	73.9	3589
49	E	345	5	50.1	4719		No further redispatch available	5				0					NA	NA	0	3589
50	B	345	3	67.2	4787		76112 MILKN 1	3				67.2					29.3	1.04	67.2	3656
51	E	115	5	96.0	4883		No further redispatch available	5				0					NA	NA	0	3656
52	A	345	1	111.7	4994		76548 INDEK-OL, 76656 DUPONT, 77794 UDG-184	1				111.7					-203.7	1.03	111.7	3768
53	F	230	6	61.9	5056		78709 ATHENSS2	6	CURRY RD-RTRDM1 115 kV	116	1.04	1.9					42.1	1.02	1.9	3769
54	E	115	5	49.9	5106		No further redispatch available	5				0					NA	NA	0	3769
55	A	115	2	179.2	5285		79940 GINNA 19	2	MORTIMER-SWDN-111 115 kV	129	1.07	69.2					17.4	1.03	69.2	3839
56	E	345	5	55.7	5341		No further redispatch available	5				0					NA	NA	0	3839
57	E	115	5	65.7	5407		No further redispatch available	5				0					NA	NA	0	3839
58	B	115	3	146.4	5553	640	76112 MILKN 1 , 76111 MILKN 2	3				146.4					-2	0.98	146.4	3985

Local Contingency Analysis Results for Addition of Wind Generation to 80% Peak Load System

AWS Data		Power Flow Data				Redispatch			Pre-Contingency				Post-Contingency							
RANK	ZONE	kV	Area #	MW	Running Sum	Δ	Units	Area	Overloaded Element	MVA Rating	OL (pu)	Revised MW	Overloaded Element	MVA Rating	OL (pu)	Contingency	Q wind (MVAr)	Voltage (pu)	Revised MW	Running Sum
59	E	345	5	49.9	5603		No further redispatch available	5				0					NA	NA	0	3985
60	F	115	5	124.3	5727		No further redispatch available	5				0					NA	NA	0	3985
61	A	345	1	123.8	5851		77794 UDG-184, 79500 NIAG. 1	1				123.8					-108	1.03	123.8	4109
62	E	115	5	88.8	5940		No further redispatch available	5				0					NA	NA	0	4109
63	F	115	6	50.4	5990		78709 ATHENSS2	6				50.4					-4.7	0.99	50.4	4159
64	A	115	1	55.2	6045		79500 NIAG. 1	1	COLDS115-CARR CRN 115 kV	36	1.28	45.2					-19.9	1.02	45.2	4204
65	E	115	5	49.9	6095		No further redispatch available	5				0					NA	NA	0	4204
66	E	115	5	49.9	6145		No further redispatch available	5				0					NA	NA	0	4204
67	B	115	2	64.3	6210		79940 GINNA 19	2				64.3					-8.8	1.04	64.3	4269
68	E	115	3	52.3	6262		76111 MILKN 2, 75754 GOUDEY 7	3				52.3					17.8	1.01	52.3	4321
69	F	345	6	49.9	6312		78709 ATHENSS2, 78708 ATHENSC2	6				49.9					2.3	1.04	49.9	4371
70	A	230	1	66.0	6378		79500 NIAG. 1, 79501 NIAG. 2	1				66					48.6	1.00	66.0	4437
71	A	115	1	109.9	6488		79501 NIAG. 2	1				109.9					-39.9	1.01	109.9	4547
72	G	345	7	50.4	6538	622	74190 ROSE GN1	7				50.4					32.5	1.01	50.4	4597
73	C	115	3	53.3	6591		75754 GOUDEY 7	3	BATH 115-BENET115 115 kV	124	1.06	33.3	FLATS115-GRNDG115 115 kV	128	1.08	BENET115-BATH 115 115kV	NA	NA	0	4597
74	C	115	3	98.6	6690		75754 GOUDEY 7, 77414 FULTN_CG, 77495 TEMPLE	3				98.6					54.6	1.02	98.6	4696
75	A	115	1	183.8	6874		79501 NIAG. 2	1	SPVL-151-ARCADE 115 kV	129	1.51	68.5	MCHS-151-ARCADE 115 kV	148	1.39	ARCADE-SPVL-151 115kV	-0.2	1.00	0.8	4697
76	A	345	1	101.8	6976		79501 NIAG. 2, 79502 NIAG. 3	1				101.8					-18.8	1.04	101.8	4798
77	C	115	3	50.2	7026		77495 TEMPLE	3	FLATS115-GRNDG115 115 kV	108	1.23	4.9					97.4	1.04	4.9	4803
78	C	115	3	49.9	7076		77495 TEMPLE, 77956 HMGENBUS	3				49.9					64	1.02	49.9	4853
79	E	115	5	763.4	7839		No further redispatch available	5				0					NA	NA	0	4853
80	E	115	5	76.6	7916		No further redispatch available	5				0					NA	NA	0	4853
81	A	345	2	131.8	8048	669	79940 GINNA 19	2				131.8	MORTIMER-SWDN-111 115 kV	136	1.16	ROCH 345-NIAG 345 345kV	NA	NA	0	4853
82	E	345	5	73.4	8121		No further redispatch available	5				0					NA	NA	0	4853
83	C	345	3	64.8	8186		77950 9M PT 2G	3				64.8					42.8	1.04	64.8	4918
84	C	345	3	49.9	8236		77950 9M PT 2G	3				49.9					116.1	1.04	49.9	4968
85	A	345	1	113.8	8349		79502 NIAG. 3	1				113.8					30.2	1.04	113.8	5082
86	C	115	3	49.9	8399		77950 9M PT 2G	3				49.9					14	1.01	49.9	5132
87	A	345	1	88.8	8488		79502 NIAG. 3, 79503 NIAG. 4	1				88.8					-59.4	1.03	88.8	5220
88	A	115	1	61.9	8550		79503 NIAG. 4	1				61.9	AM BRASS-AM BRASS 115 kV	248	1.61	HOMERHIL-DUGN-157 115kV	NA	NA	0	5220
89	E	345	5	61.4	8611		No further redispatch available	5				0					NA	NA	0	5220
90	A	230	1	125.3	8737		79503 NIAG. 4	1				125.3					-54.7	1.01	125.3	5346
91	A	115	1	71.5	8808	626	79503 NIAG. 4 , 79504 NIAG. 5	1				71.5					-23.8	1.02	71.5	5417
92	B	115	1	51.8	8860		79504 NIAG. 5	1				51.8					-18	1.04	51.8	5469
93	G	115	7	54.2	8914		74190 ROSE GN1	7				54.2					3.6	0.99	54.2	5523
94	E	115	5	49.9	8964		No further redispatch available	5				0					NA	NA	0	5523
95	A	115	2	61.4	9026		79940 GINNA 19	2				61.4					1.5	0.99	61.4	5585
96	E	115	5	49.9	9075		No further redispatch available	5				0					NA	NA	0	5585
97	F	230	5	49.9	9125		No further redispatch available	5				0					NA	NA	0	5585
98	C	345	3	95.4	9221		77950 9M PT 2G	3				95.4					51.4	1.05	95.4	5680
99	A	115	1	49.9	9271		79504 NIAG. 5	1				49.9					-9.2	1.02	49.9	5730
100	F	115	5	155.0	9426		No further redispatch available	5				0					NA	NA	0	5730
101	K	345	11	600.0	10026	913	74904 GLNWD 4, 74906 NRTPTG1	11	DUNWODIE-SHORE RD 345 kV	687	1.79	80					-13.2	1.02	80.0	5810
						7872														**5809.9**

Key:

Column	Description	Column	Description
1	AWS/TrueWind site ranking	12	Pre-contingency overload in pu
2	AWS/TrueWind site zone identification	13	Reduced wind site output required to eliminate pre-contingency overload(s)
3	Power flow interconnection bus kV level	14	Post-contingency overloaded element
4	Power flow interconnection bus area number	15	MVA rating of post-contingency overloaded element
5	Prospective wind site power output level (MW)	16	Post-contingency overload in pu
6	Running sum of prospective wind generation (MW)	17	Contingency that causes overload
7	Amount of wind generation added in each block (MW)	18	Reactive power output with final level of power output (MVAr)
8	Units used in the redispatch by power flow name and number	19	Interconnection bus voltage with final level of power output (pu)
9	Power flow area number of units used in redispatch	20	Reduced wind site output required to eliminate post-contingency overload(s)
10	Pre-contingency overloaded element	21	Running sum of final power output from each site (MW)
11	MVA rating of pre-contingency overloaded element		

Local Contingency Analysis Results for Addition of Wind Generation to Light Load System

AWS Data		Power Flow Data				Redispatch			Pre-Contingency				Post-Contingency							
RANK	ZONE	kV	Area #	MW	Running Sum	Δ	Units	Area	Overloaded Element	MVA Rating	OL (pu)	Revised MW	Overloaded Element	MVA Rating	OL (pu)	Contingency	Q wind (MVAr)	Voltage (pu)	Revised MW	Running Sum
1	E	345	6	60.5	61		78731 JMC1+7TP	6				60.5					-18.8	1.03	60.5	61
2	B	115	3	49.9	110		75963 GRNIDG 3	3				49.9					-10.6	1.03	49.9	110
3	E	115	5	49.9	160		78012 CLIMAX, 78022 FT. DRUM	5				49.9					-8.7	1.01	49.9	160
4	F	115	5	49.9	210		78022 FT. DRUM, 79305 CALPGT1	5				49.9					-11.6	1.01	49.9	210
5	A	115	1	72.5	283		76802 OXBOWNUG, 76640 DUNKGEN3	1				72.5					-10.7	1.04	72.5	283
6	E	115 230	5	400.0	683	683	79305 CALPGT1, 79306 CALPGT2, 79307 CALPST1	5				400	LOWVILLE-TAYLORVL 115 kV	135	1.154	LOWVILLE-BOONVL 115kV	-35.2	1.02	379.1	662
7	A	230	1	77.7	760		76640 DUNKGEN3, 76640 DUNKGEN3	1				77.7					-13.3	1.02	77.7	740
8	D	230	4	181.5	942		76483 NOEND3S$, 76482 NOEND2G$, 76481 NOEND1G$	4				181.5					-9.4	1.06	181.5	921
9	A	230	1	172.3	1114		76640 DUNKGEN3, 77050 HNTLY67G	1				172.3					-11.4	1.02	172.3	1093
10	D	230	4	141.1	1255	573	76481 NOEND1G$, 79515 MOS19-20, 79515 MOS19-20	4				141.1					-6.2	1.06	141.1	1234
11	G	345	6	49.9	1305		78731 JMC1+7TP, 79289 INDECK-C	6				49.9					-0.2	1.03	49.9	1284
12	A	345	1	89.3	1395		77050 HNTLY67G, 77050 HNTLY67G	1				89.3					-12.7	1.04	89.3	1374
13	E	115	3	68.2	1463		75963 GRNIDG 3, 76112 MILKN 1	3				68.2					-9.6	1.02	68.2	1442
14	A	230	1	109.5	1572		77050 HNTLY67G, 75523 KINTIG24	1				109.5					-6.4	1.02	109.5	1551
15	F	345	6	49.9	1622		79289 INDECK-C	6				49.9					-2.8	1.03	49.9	1601
16	E	115	5	89.6	1712		79307 CALPST1	5				80					-4.1	1.03	80	1681
17	A	345	1	74.2	1786		75523 KINTIG24	1				74.2					-10.6	1.04	74.2	1755
18	A	230	1	88.7	1875	619	75523 KINTIG24	1				88.7					-8.9	1.02	88.7	1844
19	A	345	1	253.4	2128		75523 KINTIG24	1				253.4					-19.9	1.04	253.4	2098
20	A	115	1	133.5	2262		75523 KINTIG24, 76296 LEA 1G $, 76297 LEA 2G $, 7(	1				133.5					-9.3	1.04	133.5	2231
21	A	115	1	159.2	2421		76298 LEA 3G $, 76299 LEA 4S $, 76548 INDEK-OL, 7	1				159.2	SLVRC115-DUNKIRK1 115 kV	117	1.42	SLVRC115-NANG-141 115kV	-44.4	1.03	110.3	2341
22	E	115	5	55.9	2477	602	No further redispatch available	5				0					N/A	N/A	0	2341
23	A	115	2	181.9	2658		79943 RUS 3G, 79944 RUS 4G, 77121 SENECAP, 79940 GINNA 19	2				181.9					-20.1	1.02	181.9	2523
24	A	115	2	172.3	2831		79940 GINNA 19	2	MORTIMER-SWDN-111 115 kV	129	1.34	101.4					-15.3	1.00	101.4	2625
25	A	115	2	197.3	3028		79940 GINNA 19	2	BRCKPTHS-SWDN-111 115 kV	107	2.35	0					N/A	N/A	0	2625
26	B	115	2	73.5	3102	625	79940 GINNA 19	2				73.5					-11.6	1.01	73.5	2698
27	D	115	4	49.9	3152		79515 MOS19-20, 79516 MOS21-22	4				49.9					-5.8	1.04	49.9	2748
28	A	230	1	67.2	3219		76656 DUPONT, 77794 UDG-184	1				67.2					-1.5	1.02	67.2	2815
29	B	115	2	61.5	3280		79940 GINNA 19	2				61.5					-18.3	1.03	61.5	2877
30	D	230	4	60.4	3341		79516 MOS21-22, 79516 MOS21-22	4				60.4					14.2	1.07	60.4	2937
31	C	115	3	108.0	3449		76112 MILKN 1, 76111 MILKN 2	3				108					-11	1.03	108	3045
32	A	115	2	73.3	3522		79940 GINNA 19	2	MORTIMER-SWDN-111 115 kV	129	1.04	0					N/A	N/A	0	3045
33	E	230	5	91.8	3614		No further redispatch available	5				0					N/A	N/A	0	3045
34	C	230	3	50.1	3664		76111 MILKN 2	3				50.1					1.5	1.00	50.1	3095
35	A	230	1	88.8	3753	651	77794 UDG-184, 79500 NIAG. 1	1				88.8					-2.7	1.02	88.8	3184
36	F	345	6	49.9	3803		79289 INDECK-C, 78714 GLENVIL2	6				49.9					19	1.03	49.9	3234
37	A	115	1	67.7	3870		79500 NIAG. 1	1				67.7					16.1	1.01	67.7	3302
38	A	115	1	68.6	3939		79500 NIAG. 1, 79501 NIAG. 2	1				68.6					-16.7	1.00	68.6	3370
39	F	345	6	61.4	4000		78714 GLENVIL2	6				61.4					8.7	1.03	61.4	3432
40	C	115	3	67.7	4068		76111 MILKN 2	3				67.7	EELPO115-MEYER115 115 kV	149	1.36	EELPO115-FLATS115 115kV	-0.7	1.03	4.6	3436
41	E	115	5	52.3	4120		No further redispatch available	5				0					N/A	N/A	0	3436
42	E	115	4	49.9	4170		79516 MOS21-22, 79518 MOS25-26	4				49.9					-13.9	1.05	49.9	3486
43	E	115	5	82.6	4253		No further redispatch available	5				0					N/A	N/A	0	3486
44	A	115	1	82.1	4335		79501 NIAG. 2	1				82.1					-20.5	1.00	82.1	3568
45	C	115	3	51.8	4387		76111 MILKN 2	3				51.8					-2	1.01	51.8	3620
46	C	230	3	58.6	4445		76111 MILKN 2, 77950 9M PT 2G	3				58.6					0.1	1.00	58.6	3679
47	A	345	1	150.2	4595	649	79501 NIAG. 2, 79502 NIAG. 3	1				150.2					-8.4	1.05	150.2	3829
48	C	115	3	73.9	4669		77950 9M PT 2G	3				73.9					6.1	1.03	73.9	3903
49	E	345	5	50.1	4719		No further redispatch available	5				0					N/A	N/A	0	3903
50	B	345	3	67.2	4787		77950 9M PT 2G	3				67.2					2.9	1.05	67.2	3970
51	E	115	5	96.0	4883		No further redispatch available	5				0					N/A	N/A	0	3970
52	A	345	1	111.7	4994		79502 NIAG. 3	1				111.7					-13.6	1.04	111.7	4082
53	F	230	6	61.9	5056		78714 GLENVIL2	6				61.9					31.6	1.01	61.9	4144
54	E	115	5	49.9	5106		No further redispatch available	5				0					N/A	N/A	0	4144
55	A	115	2	179.2	5285		79940 GINNA 19	2	MORTIMER-SWDN-111 115 kV	129	1.12	0					N/A	N/A	0	4144
56	E	345	5	55.7	5341		No further redispatch available	5				0					N/A	N/A	0	4144
57	E	115	5	65.7	5407		No further redispatch available	5				0					N/A	N/A	0	4144
58	B	115	3	146.4	5553	640	77950 9M PT 2G	3				146.4					-13.9	0.98	146.4	4290

Local Contingency Analysis Results for Addition of Wind Generation to Light Load System

AWS Data		Power Flow Data				Redispatch			Pre-Contingency				Post-Contingency							
RANK	ZONE	kV	Area #	MW	Running Sum	Δ	Units	Area	Overloaded Element	MVA Rating	OL (pu)	Revised MW	Overloaded Element	MVA Rating	OL (pu)	Contingency	Q wind (MVAr)	Voltage (pu)	Revised MW	Running Sum
59	E	345	5	49.9	5603		No further redispatch available	5				0					N/A	N/A	0	4290
60	F	115	5	124.3	5727		No further redispatch available	5				0					N/A	N/A	0	4290
61	A	345	1	123.8	5851		79502 NIAG. 3, 79503 NIAG. 4	1				123.8					-9.3	1.04	123.8	4414
62	E	115	5	88.8	5940		No further redispatch available	5				0					N/A	N/A	0	4414
63	F	115	6	50.4	5990		78714 GLENVIL2, 78746 CETI, 78811 BESI20G3	6				50.4					-5.4	1.01	50.4	4464
64	A	115	1	55.2	6045		79503 NIAG. 4	1	COLDS115-CARR CRN 115 kV	36	1.34	43.1					-9.4	1.01	43.1	4507
65	E	115	5	49.9	6095		No further redispatch available	5				0					N/A	N/A	0	4507
66	E	115	5	49.9	6145		No further redispatch available	5				0					N/A	N/A	0	4507
67	B	115	2	64.3	6210		79940 GINNA 19	2				64.3					-16.1	1.02	64.3	4572
68	E	115	3	52.3	6262		77950 9M PT 2G	3				52.3					11.6	1.02	52.3	4624
69	F	345	6	49.9	6312		78811 BESI20G3	6				49.9					-4.9	1.03	49.9	4674
70	A	230	1	66.0	6378		79503 NIAG. 4, 79504 NIAG. 5	1				66					-5.3	1.02	66	4740
71	A	115	1	109.9	6488		79504 NIAG. 5	1				109.9					-26.2	1.01	109.9	4850
72	G	345	7	50.4	6538	622	74190 ROSE GN1	7				50.4					12.9	1.02	50.4	4900
73	C	115	3	53.3	6591		77950 9M PT 2G	3				53.3					1.1	1.03	53.3	4953
74	C	115	3	98.6	6690		77950 9M PT 2G	3				98.6					23.5	1.02	98.6	5052
75	A	115	1	183.8	6874		79504 NIAG. 5	1	SPVL-151-ARCADE 115 kV	157	1.38	78.4	SPVL-151-ARCADE 115 kV	171	1.30	ARCADE-MCHS-151 115kV	-4.3	1.00	17.5	5069
76	A	345	1	101.8	6976		79504 NIAG. 5, 79505 NIAG. 6	1				101.8					-4	1.05	101.8	5171
77	C	115	3	50.2	7026		77950 9M PT 2G	3	FLATS115-GRNDG115 115 kV	133	1.05	40.2					43.1	1.03	40.2	5211
78	C	115	3	49.9	7076		77950 9M PT 2G	3				49.9					30.4	1.02	49.9	5261
79	E	115	5	763.4	7839		No further redispatch available	5				0					N/A	N/A	0	5261
80	E	115	5	76.6	7916		No further redispatch available	5				0					N/A	N/A	0	5261
81	A	345	2	131.8	8048	669	79940 GINNA 19	2	STA 162-STA 158S 115 kV	46.6	1.30	0					N/A	N/A	0	5261
82	E	345	5	73.4	8121		No further redispatch available	5				0					N/A	N/A	0	5261
83	C	345	3	64.8	8186		77950 9M PT 2G	3				64.8					-12.9	1.04	64.8	5326
84	C	345	3	49.9	8236		77950 9M PT 2G	3				49.9					10.8	1.04	49.9	5376
85	A	345	1	113.8	8349		79505 NIAG. 6, 79506 NIAG. 7	1				113.8					5.4	1.04	113.8	5490
86	C	115	3	49.9	8399		77950 9M PT 2G	3				49.9					21.2	1.02	49.9	5540
87	A	345	1	88.8	8488		79506 NIAG. 7	1				88.8					-5.7	1.04	88.8	5629
88	A	115	1	61.9	8550		79506 NIAG. 7	1	COLDS115-CARR CRN 115 kV	36	1.03	0					N/A	N/A	0	5629
89	E	345	5	61.4	8611		No further redispatch available	5				0					N/A	N/A	0	5629
90	A	230	1	125.3	8737		79506 NIAG. 7, 79507 NIAG. 8	1				125.3					-2.3	1.02	125.3	5754
91	A	115	1	71.5	8808	626	79507 NIAG. 8	1				71.5					-14.2	1.01	71.5	5825
92	B	115	1	51.8	8860		79507 NIAG. 8, 79508 NIAG. 9	1				51.8					-14.6	1.00	51.8	5877
93	G	115	7	54.2	8914		74190 ROSE GN1	7				54.2					-4.1	1.01	54.2	5931
94	E	115	5	49.9	8964		No further redispatch available	5				0					N/A	N/A	0	5931
95	A	115	2	61.4	9026		79940 GINNA 19	2	STA 162-STA 158S 115 kV	46.6	1.31	0					N/A	N/A	0	5931
96	E	115	5	49.9	9075		No further redispatch available	5				0					N/A	N/A	0	5931
97	F	230	5	49.9	9125		No further redispatch available	5				0					N/A	N/A	0	5931
98	C	345	3	95.4	9221		77950 9M PT 2G	3				95.4					60.4	1.05	95.4	6027
99	A	115	1	49.9	9271		79508 NIAG. 9	1				49.9					8.6	1.01	49.9	6077
100	F	115	5	155.0	9426		No further redispatch available	5				0					N/A	N/A	0	6077
101	K	345	11	600.0	10026	913	74905 GLNWD 5	11	DUNWODIE-SHORE RD 345 kV	699	1.79	48					-12.8	1.01	48	6125
						7872														**6124.6**

Key:

Column	Description	Column	Description
1	AWS/TrueWind site ranking	12	Pre-contingency overload in pu
2	AWS/TrueWind site zone identification	13	Reduced wind site output required to eliminate pre-contingency overload(s)
3	Power flow interconnection bus kV level	14	Post-contingency overloaded element
4	Power flow interconnection bus area number	15	MVA rating of post-contingency overloaded element
5	Prospective wind site power output level (MW)	16	Post-contingency overload in pu
6	Running sum of prospective wind generation (MW)	17	Contingency that causes overload
7	Amount of wind generation added in each block (MW)	18	Reactive power output with final level of power output (MVAr)
8	Units used in the redispatch by power flow name and number	19	Interconnection bus voltage with final level of power output (pu)
9	Power flow area number of units used in redispatch	20	Reduced wind site output required to eliminate post-contingency overload(s)
10	Pre-contingency overloaded element	21	Running sum of final power output from each site (MW)
11	MVA rating of pre-contingency overloaded element		

Appendix C. MARS Program Description

MARS Program Description

The Multi-Area Reliability Simulation program (MARS) enables the electric utility planner to quickly and accurately assess the reliability of a generation system comprised of any number of interconnected areas.

MARS MODELING TECHNIQUE

A sequential Monte Carlo simulation forms the basis for MARS. The Monte Carlo method provides a fast, versatile, and easily-expandable program that can be used to fully model many different types of generation and demand-side options.

In the sequential Monte Carlo simulation, chronological system histories are developed by combining randomly-generated operating histories of the generating units with the inter-area transfer limits and the hourly chronological loads. Consequently, the system can be modeled in great detail with accurate recognition of random events, such as equipment failures, as well as deterministic rules and policies which govern system operation, without the simplifying or idealizing assumptions often required in analytical methods.

RELIABILITY INDICES AVAILABLE FROM MARS

The following reliability indices are available on both an isolated (zero ties between areas) and interconnected (using the input tie ratings between areas) basis:

- Daily LOLE (days/year)
- Hourly LOLE (hours/year)
- LOEE (MWh/year)
- Frequency of outage (outages/year)
- Duration of outage (hours/outage)
- Need for initiating emergency operating procedures (days/year)

The use of Monte Carlo simulation allows for the calculation of probability distributions, in addition to expected values, for all of the reliability indices. These values can be calculated both with and without load forecast uncertainty.

DESCRIPTION OF PROGRAM MODELS

Loads

The loads in MARS are modeled on an hourly, chronological basis for each area being studied. The program has the option to modify the input hourly loads through time to meet specified annual or monthly peaks and energies. Uncertainty on the annual peak load forecast can also be modeled, and can vary by area on a monthly basis.

Generation

MARS has the capability to model the following different types of resources:

- Thermal
- Energy-limited
- Cogeneration
- Energy-storage
- Demand-side management

An energy-limited unit can be modeled stochastically as a thermal unit with an energy probability distribution (Type 1 energy-limited unit), or deterministically as a load modifier (Type 2 energy-limited unit). Cogeneration units are modeled as thermal units with an associated hourly load demand. Energy-storage and demand-side management are modeled as load modifiers.

For each unit modeled, the user specifies the installation and retirement dates and planned maintenance requirements. Other data such as maximum rating, available capacity states, state transition rates, and net modification of the hourly loads are input depending on the unit type.

The planned outages for all types of units in MARS can be specified by the user or automatically scheduled by the program on a weekly basis. The program schedules planned maintenance to levelize reserves on either an area, pool, or system basis. MARS also has the option of reading a maintenance schedule developed by a previous run and modifying it as specified by the user through any of the maintenance input data. This schedule can then be saved for use by subsequent runs.

Thermal Units. In addition to the data described previously, thermal units (including Type 1 energy-limited units and cogeneration) require data describing the available capacity states in which the unit can operate. This is input by specifying the maximum rating of each unit and the rating of each capacity state as a per unit of the unit's maximum rating. A maximum of eleven capacity states are allowed for each unit, representing decreasing amounts of available capacity as a result of the outages of various unit components.

Because MARS is based on a sequential Monte Carlo simulation, it uses state transition rates, rather than state probabilities, to describe the random forced outages of the thermal units. State probabilities give the probability of a unit being in a given capacity state at any particular time, and can be used if you assume that the unit's capacity state for a given hour is independent of its state at any other hour. Sequential Monte Carlo simulation recognizes the fact that a unit's capacity state in a given hour is dependent on its state in previous hours and influences its state in future hours. It thus requires the additional information that is contained in the transition rate data.

Energy-Limited Units. Type 1 energy-limited units are modeled as thermal units whose capacity is limited on a random basis for reasons other than the forced outages on the unit. This unit type can be used to model a thermal unit whose operation may be restricted due to the unavailability of fuel, or a hydro unit with limited water availability. It can also be used to model technologies such as wind or solar; the capacity may be available but the energy output is limited by weather conditions.

Type 2 energy-limited units are modeled as deterministic load modifiers. They are typically used to model conventional hydro units for which the available water is assumed to be known with little or no uncertainty. This type can also be used to model certain types of contracts. A Type 2 energy-limited unit is described by specifying a maximum rating, a minimum rating, and a monthly available energy. This data can be changed on a monthly basis. The unit is scheduled on a monthly basis with the unit's minimum rating dispatched for all of the hours in the month. The remaining capacity and energy can be scheduled in one of two ways. In the first method, it is scheduled deterministically so as to reduce the peak loads as much as possible. In the second approach, the peak-shaving portion of the unit is scheduled only in those hours in which the available thermal capacity is not sufficient to meet the load; if there is sufficient thermal capacity, the energy of the Type 2 energy-limited units will be saved for use in some future hour when it is needed.

Cogeneration. MARS models cogeneration as a thermal unit with an associated load demand. The difference between the unit's available capacity and its load requirements represents the amount of capacity that the unit can contribute to the system. The load demand is input by specifying the hourly loads for a typical week (168 hourly loads for Monday through Sunday). This load profile can be changed on a monthly basis. Two types of cogeneration are modeled in the program, the difference being whether or not the system provides back-up generation when the unit is unable to meet its native load demand.

Energy-Storage and DSM. Energy-storage units and demand-side management are both modeled as deterministic load modifiers. For each such unit, the user specifies a net hourly load modification for a typical week which is subtracted from the hourly loads for the unit's area.

Transmission System

The transmission system between interconnected areas is modeled through transfer limits on the interfaces between pairs of areas. Simultaneous transfer limits can also be modeled in which the total flow on user-defined groups of interfaces is limited. Random forced outages on the interfaces are modeled in the same manner as the outages on thermal units, through the use of state transition rates.

The transfer limits are specified for each direction of the interface or interface group and can be input on a monthly basis. The transfer limits can also vary hourly according to the availability of specified units and the value of area loads.

Contracts

Contracts are used to model scheduled interchanges of capacity between areas in the system. These interchanges are separate from those that are scheduled by the program as one area with excess capacity in a given hour provides emergency assistance to a deficient area.

Each contract can be identified as either firm or curtailable. Firm contracts will be scheduled regardless of whether or not the sending area has sufficient resources on an isolated basis, but they can be curtailed because of interface transfer limits. Curtailable contracts will be scheduled only to the extent that the sending area has the necessary resources on its own or can obtain them as emergency assistance from other areas.

Emergency Operating Procedures

Emergency operating procedures are steps undertaken by a utility system as the reserve conditions on the system approach critical levels. They consist of load control and generation supplements which can be implemented before load has to be actually disconnected. Load control measures could include disconnecting interruptible loads, public appeals to reduce demand, and voltage reductions. Generation supplements could include overloading units, emergency purchases, and reduced operating reserves.

The need for a utility to begin emergency operating procedures is modeled in MARS by evaluating the daily LOLE at specified margin states. The user specifies these margin states for each area in terms of the benefits realized from each emergency measure, which can be expressed in MW, as a per unit of the original or modified load, and as a per unit of the available capacity for the hour.

The user can also specify monthly limits on the number of times that each emergency procedure is initiated, and whether each EOP benefits only the area itself, other areas in the same pool, or areas throughout the system. Staggered implementation of EOPs, in which the deficient area must initiate a specified number of EOPs before non-deficient areas begin implementation, can also be modeled.

Resource Allocation Among Areas

The first step in calculating the reliability indices is to compute the area margins on an isolated basis, for each hour. This is done by subtracting from the total available capacity in the area for the hour the load demand for the hour. If an area has a positive or zero margin, then it has sufficient capacity to meet its load. If the area margin is negative, the load exceeds the capacity available to serve it, and the area is in a loss-of-load situation.

If there are any areas that have a negative margin after the isolated area margins have been adjusted for curtailable contracts, the program will attempt to satisfy those deficiencies with capacity from areas that have positive margins. Two methods are available for determining how the reserves from areas with excess capacity are allocated among the areas that are deficient. In the first approach, the user specifies the order in which an area with excess resources provides assistance to areas that are deficient. The second method shares the available excess reserves among the deficient areas in proportion to the size of their shortfalls.

The user can also specify that areas within a pool will have priority over outside areas. In this case, an area must assist all deficient areas within the same pool, regardless of the order of areas in the priority list, before assisting areas outside of the pool. Pool-sharing agreements can also be modeled in which pools provide assistance to other pools according to a specified order.

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