

# Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation

## Preprint

M. Milligan  
*National Renewable Energy Laboratory*

K. Porter  
*Exeter Associates, Inc.*

*To be presented at WindPower 2008  
Houston, Texas  
June 1–4, 2008*

**Conference Paper**  
**NREL/CP-500-43433**  
**June 2008**

NREL is operated by Midwest Research Institute • Battelle Contract No. DE-AC36-99-GO10337



## NOTICE

The submitted manuscript has been offered by an employee of the Midwest Research Institute (MRI), a contractor of the US Government under Contract No. DE-AC36-99GO10337. Accordingly, the US Government and MRI retain a nonexclusive royalty-free license to publish or reproduce the published form of this contribution, or allow others to do so, for US Government purposes.

This report was prepared as an account of work sponsored by an agency of the United States government. Neither the United States government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States government or any agency thereof.

Available electronically at <http://www.osti.gov/bridge>

Available for a processing fee to U.S. Department of Energy and its contractors, in paper, from:

U.S. Department of Energy  
Office of Scientific and Technical Information  
P.O. Box 62  
Oak Ridge, TN 37831-0062  
phone: 865.576.8401  
fax: 865.576.5728  
email: <mailto:reports@adonis.osti.gov>

Available for sale to the public, in paper, from:

U.S. Department of Commerce  
National Technical Information Service  
5285 Port Royal Road  
Springfield, VA 22161  
phone: 800.553.6847  
fax: 703.605.6900  
email: [orders@ntis.fedworld.gov](mailto:orders@ntis.fedworld.gov)  
online ordering: <http://www.ntis.gov/ordering.htm>



# Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation

Michael Milligan  
National Renewable Energy Laboratory  
1617 Cole Blvd.  
Golden, CO 80401  
303-384-6927  
303-384-6901 (fax)  
michael\_milligan@nrel.gov  
[www.nrel.gov/wind](http://www.nrel.gov/wind)

Kevin Porter  
Senior Analyst  
Exeter Associates, Inc.  
5565 Sterrett Place  
Suite 310  
Columbia, Maryland 21044  
410-992-7500  
410-992-3445 fax  
porter@exeterassociates.com  
[www.exeterassociates.com](http://www.exeterassociates.com)

## Abstract

Electric systems must have sufficient reserves so that resources are adequate to meet customer demand. Because electricity demand cannot be known in advance with certainty, and because generation can experience mechanical or electrical failures which take it out of service (i.e., experience forced outages), a planning reserve that consists of installed capacity in excess of load requirements is necessary to maintain reliability. This reserve is applied in the planning time frame (i.e., one year or more), and is a determination of system adequacy: is there sufficient installed generation to meet load obligations? Capacity requirements are currently implemented differently from region to region, but a new Resource Adequacy Assessment standard is under development by the North American Electric Reliability Corporation (NERC) which would establish consistent requirements for NERC regions to assess adequacy. As wind achieves greater penetration in the United States, it will become important to address the issue of how wind contributes to system adequacy. Wind's contribution to adequacy is its capacity value.

The level of wind capacity value is a matter of debate in some regions, due to the variability of wind power and its relationship with load. Utilities and other entities typically allocate some capacity value to wind power, although at a lower level than other energy technologies. All of the nation's regional transmission organizations (RTOs) assign a capacity value to wind, and some states, as well as studies in Colorado and Minnesota, have also determined that wind energy has a capacity value.

This paper examines the various methods used to estimate the capacity value of wind and is an update of a paper we presented at WINDPOWER 2005. This paper summarizes several important state and regional studies that examine the capacity value of wind energy, how different regions define and implement capacity reserve requirements across the country, and how wind energy is defined as a capacity resource in those regions. Updates on changes to the capacity value of wind in ERCOT, ISO New England, PJM, California, and New York will be provided. We also provide an overview of wind capacity value in Europe.

## Introduction and Overview

With over 18 GW of installed wind capacity in the United States as of first quarter 2008, and another 4 GW under construction, the question of wind's capacity value (sometimes called capacity credit) is gaining more attention.<sup>1</sup> Wind's low cost and environmental benefits, and the higher cost of competing fuels such as natural gas, mean that system planners will need to grapple with how to determine the capacity value of wind energy. It does seem clear that wind's primary value is as an energy resource, but to the extent to which it contributes towards system adequacy is an important question.

Effective load carrying capability (ELCC) is an often-used metric to assess capacity credit, not only for wind plants, but for any power plant. A typical power plant has a relatively low forced outage rate, which implies a high availability rate. This translates into an ELCC value that is typically a large percentage of the conventional plant rated capacity. In fact, the ELCC can often be approximated by the unforced capacity  $C(1-r)$  where  $C$  = capacity and  $r$  = forced outage rate.

Wind generators typically have very high mechanical availability, exceeding 95% in many instances; i.e., the forced outage rate is often below 5%. However, because wind generators only generate electricity when the wind is blowing, wind's availability rate (the rate that power and energy can actually be provided) is a function of the wind speed throughout the year. Therefore, the *effective* forced outage rate for wind generators may be much higher, from 50% to 80%, when recognizing the variable availability of wind. In addition, wind's value to the electric system may also vary. The output from some wind generators may have a high correlation with load and thereby can be seen as supplying capacity when it is most needed. In this situation, a wind generating plant should have a relatively high capacity credit. The output from other wind generating plants may not be as highly correlated with system load, and therefore would have a

---

<sup>1</sup> American Wind Energy Association. "With Uncertainty Looming Over Federal Incentive, U.S. Wind Industry Installs 1,400 MW in First Quarter." May 7, 2008.  
[http://www.awea.org/newsroom/releases/AWEA\\_Market\\_Release\\_Q108.html](http://www.awea.org/newsroom/releases/AWEA_Market_Release_Q108.html).

lower value to the electric system and should receive a lower capacity credit<sup>2</sup>. The correlation of wind generation with system load, along with the wind generator's outage rate, is the primary determinants of wind capacity credit. There are other lesser influences that are described later in this paper.

## Emerging Resource Adequacy Standards

This paper describes current approaches and processes used in North America and other parts of the world for determining the capacity value of wind. As capacity value is a component used in determining resource adequacy, the ongoing effort by NERC to develop standards is an important related event. As mandated by the Energy Policy Act of 2005, reliability organizations are to "conduct periodic assessments of the reliability and adequacy of the bulk power system of North America."<sup>3</sup>

This future standard or standards, when approved, would establish requirements for each of the eight Regional Reliability Organizations to create a metric or metrics and to assess resource adequacy for its region. The Resource Adequacy SAR (Standard Authorization Request) drafting team has completed its SAR Form<sup>4</sup> and NERC has assigned this to a group of projects to be completed in 2009.

To address resource adequacy and other issues related to variable generation such as wind and solar technologies, NERC has created a work group called the Integration of Variable Generation Task Force (IVGTF) to develop a white paper to describe planning and operational issues, review NERC standards for any gaps, and provide conclusions and recommendations. The future results of the IVGTF efforts could provide more detailed guidance on the issue of capacity value and on standards that may be needed.

## System Resource Adequacy

Power system resource adequacy is typically measured by conducting a comparison of installed capacity and peak loads over some time horizon. Because all generators have a non-zero probability of failure, and because loads cannot be known with certainty in advance, the system must have a planning reserve margin. The planning reserve margin is a level of installed capacity that exceeds expected peak demand, and is typically analyzed one or more years in advance. One often-used approach is to use a fixed level of planning reserve, such as 15%, and determine whether the installed generation fleet capacity is 15% higher than expected load. If the installed capacity meets the planning reserve criterion, the system is considered adequate. However, this approach does not take account of the role of generators' forced outage rates on adequacy, nor does it quantify the percentage of time that the system may be inadequate.

---

<sup>2</sup> Milligan, M. and B. Parsons (1999), "A Comparison and Case Study of Capacity Credit Algorithms for Wind Power Plants. Journal of Wind Engineering. Multi-Science Publishing Co. LTD. Brentwood, Essex, United Kingdom. Vol 23, No. 3, 1999.

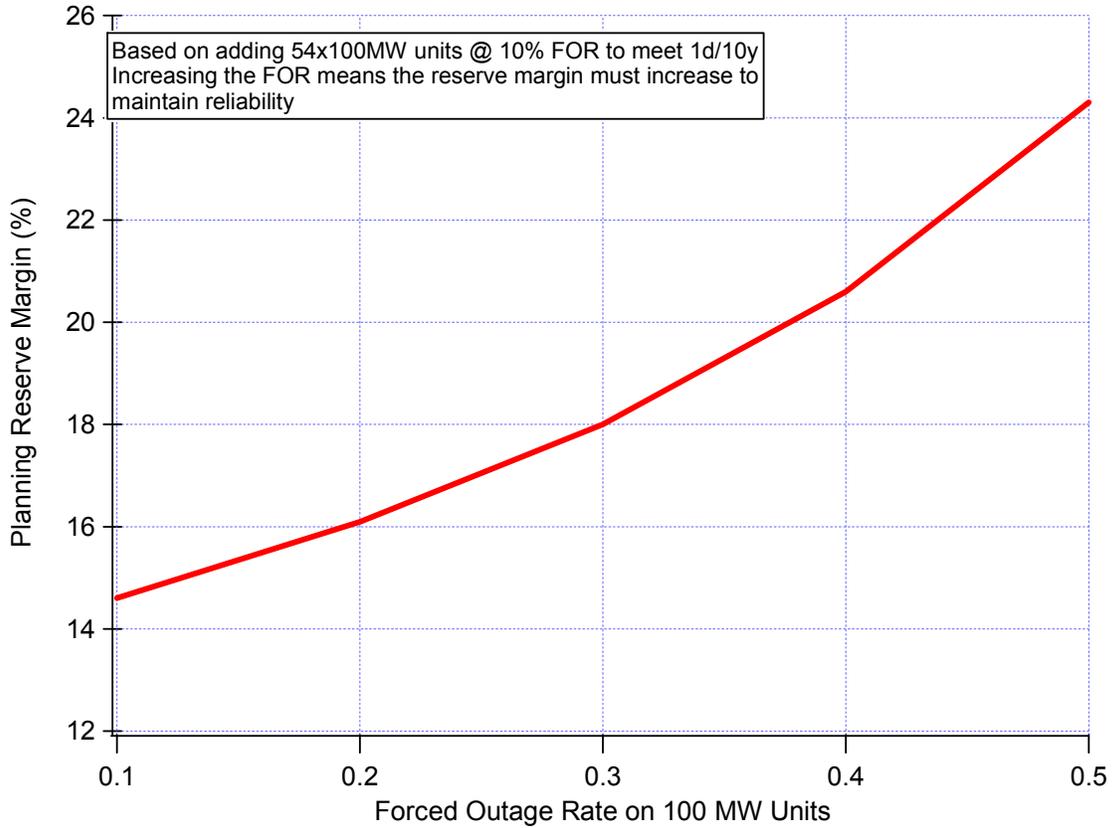
<sup>3</sup> Energy Policy Act Of 2005, Title XII-electricity, Subtitle A-Reliability Standards, (g) RELIABILITY REPORTS

<sup>4</sup> [http://www.nerc.com/~filez/standards/Resource\\_Adequacy.html](http://www.nerc.com/~filez/standards/Resource_Adequacy.html)

A more rigorous approach to assess system adequacy is based on power system reliability theory. Using a model of the hourly loads, generation capacity, and forced outage rates, loss of load probability (LOLP) or a similar reliability metric can be calculated for the system. Since LOLP is a probability that is typically calculated for each hour, it is desirable to convert this to an annual measure of system adequacy. This is often done by calculating the product of probabilities and hours, resulting in loss of load expectation (LOLE). LOLE is measured in units such as hours/year, days/year, or days/10 years, and provides a measure of *how adequate* the system is.

With modern interconnected power systems, the LOLP does not necessarily measure the probability that load will be shed because of insufficient generation. The LOLP metric measures the risk that generation cannot meet the peak demand unless capacity is imported. When performing a reliability analysis it is necessary to select a risk target. This is often chosen to be a LOLE of 1 day per 10 years. This roughly corresponds to a 0.9997 probability that generation will be sufficient to cover load without unexpected imports. Other reliability targets can also be chosen, such as 1d/30y (corresponding to a probability of 0.999909) or 1d/100y (probability 0.999973). Other reliability targets or metrics, such as expected unserved energy (EUE) can be chosen if desired by the reliability organization. For convenience, we will use 1d/10y as our reliability target, but the results and discussion of this paper are qualitatively consistent with any other reliability target.

A fixed reserve margin does not directly address the level of system adequacy that will be delivered by a given level of installed capacity. For a system with approximately 10% of its capacity in 100-MW units with varying forced outage rates, the relationship between these forced outage rates and the required installed capacity that would deliver a 1d/10y level of system adequacy appears in Figure 1. The data that underlies the graph uses hourly load data from the California ISO. Instead of using the existing generator fleet, a hypothetical generator mix was developed that consists of ninety-five 500-MW units, each with a forced outage rate of 9%. The base case also included fifty-four 100-MW units, each with a forced outage rate of 10%. This mix of generation achieved a 1-day-in-10-year reliability level. As the forced outage rate increases on the 100-MW units, the required planning reserve margin to maintain the 1d/10y system adequacy level increases. This clearly suggests that two systems with the same reserve margin percentage do not necessarily achieve the same level of system adequacy.



**Figure 1. As forced outage rates increase, larger planning reserve margins as percent of peak are required to maintain system adequacy at a 1d/10y level.**

Most conventional generating units have forced outage rates less than 0.10 (10%). However, many units have forced outage rates that are significantly higher, as demonstrated by Figure 2. The point of these figures is to demonstrate that the relationship between generator forced outage rates and system adequacy is not academic; different systems with the same planning reserve level will exhibit different levels of reliability over time.

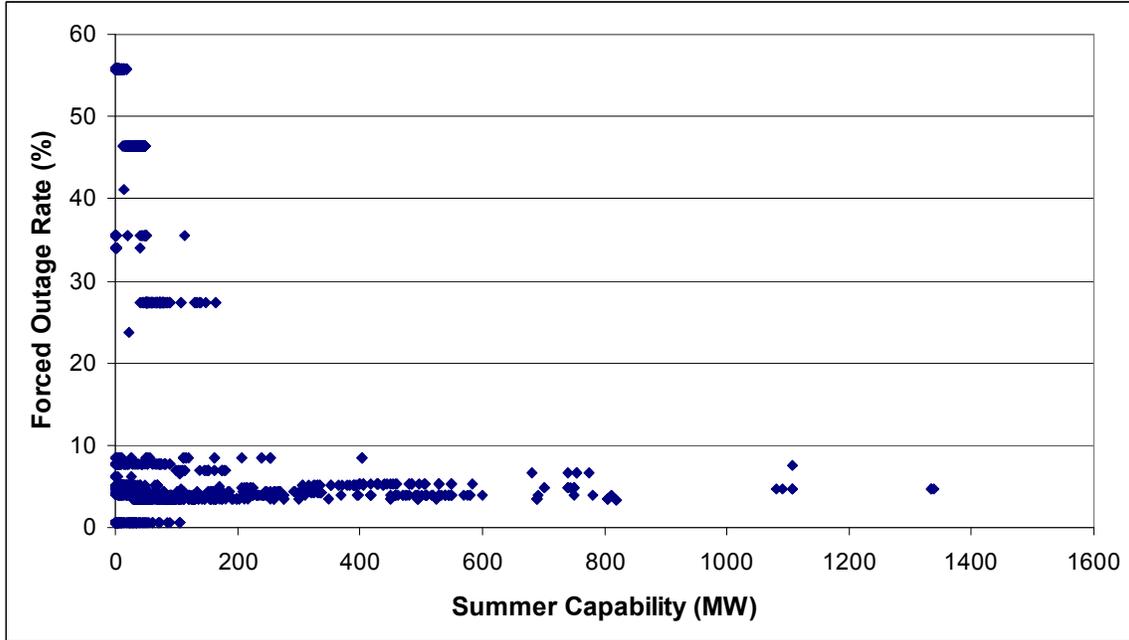


Figure 2. Data from the Western Electricity Coordinating Council (WECC) shows that some forced outage rates are much higher than 0.10.

It is often useful to determine the contribution that an individual generator makes to overall system adequacy. This is a straightforward process and has been well-known for several decades. The approach results in a capacity contribution that is called the effective load carrying capability (ELCC). ELCC is a measure of the additional load that the system can supply with the particular generator of interest, with *no net change in reliability*. Although ELCC can be based on several alternative reliability measures (such as LOLE or EUE) we focus on LOLE for convenience in this paper.

## Effective Load Carrying Capability

ELCC decomposes the individual generator’s contribution to system reliability. It can discriminate among generators with differing levels of reliability, size, and on-peak vs. off-peak delivery. Plants that are consistently able to deliver during periods of high demand have a high ELCC, and less reliable plants have a lower ELCC. For variable generators such as wind, the method can discriminate between wind regimes that consistently deliver during high-risk periods, sometimes deliver during high-risk periods, or never deliver during high-risk periods. In fact, ELCC can provide for a continuum of capacity values over these potential outcomes.

ELCC is driven by the timing of high LOLP hours. Figure 3 shows a typical LOLP duration curve. A generator that contributes a significant level of capacity during the top 200 hours will have a higher capacity value (ELCC) than a unit that delivers the same capacity during hours 600 – 800 instead. Generators that reduce LOLP the most will make the highest contribution to system adequacy and reliability, and will therefore have a higher ELCC. If a plant were unable to generate any power during the approximately 800 hours shown in the graph, its capacity value would be very close to zero.

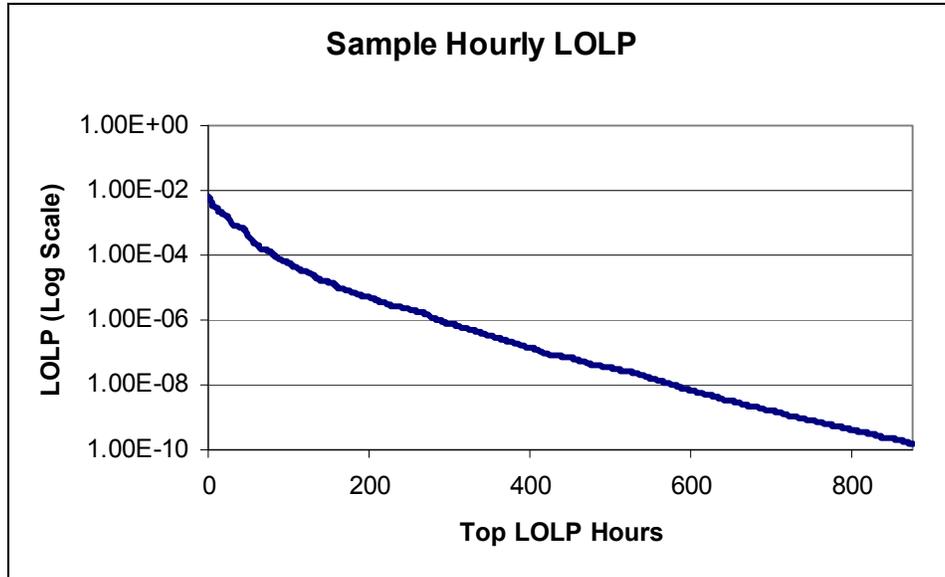


Figure 3. LOLP drops quickly from its maximum value as shown by this LOLP-duration curve. Note the logarithmic LOLP scale.

To calculate ELCC, a database is required that contains hourly load requirements and generator characteristics. For conventional generators, rated capacity, forced outage rates, and specific maintenance schedules are the primary requirements. For a variable resource such as wind, at least one year of hourly power output is required, but more data is always better. Over the decades that ELCC has been widely applied, it has been used with a number of different reference units. Some early work (for example, Garver<sup>5</sup>) measured the capacity value of a generator against a perfectly reliable unit. Because such a unit does not exist, we prefer the alternative of measuring capacity value relative to a benchmark unit. Although we would prefer a widely adopted benchmark value (for example, a gas unit with a forced outage rate of 5%) to allow for easier comparison among studies, it is important that the benchmark unit is clearly identified, and *all* units in a given region, such as a balancing authority, should be measured against the same benchmark.

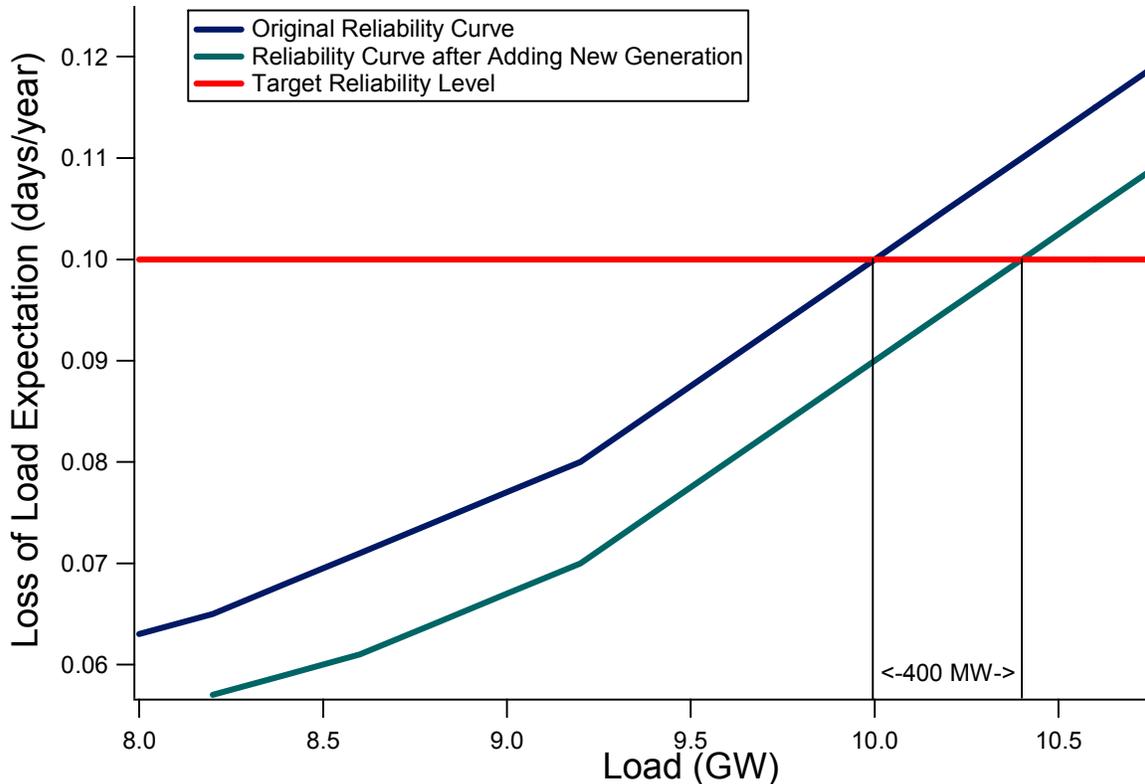
Although there are some variations in the approach, ELCC is calculated in several steps. Most commonly, the system is modeled without the generator of interest. For this discussion, we assume that the generator of interest is a renewable generator, but this does not need to be the case. The loads are adjusted to achieve a given level of reliability.

Once the desired LOLE target is achieved, the renewable generator is added to the system and the model is re-run. The new, lower LOLE (higher reliability) is noted, and the generator is removed from the system. Then the benchmark unit is added to the system in small incremental capacities until the LOLE with the benchmark unit matches the LOLE that was achieved with the renewable generator. The capacity of the benchmark unit is then noted, and that becomes the

<sup>5</sup> Garver, L. L. (1966) "Effective Load-Carrying Capability of Generating Units." IEEE Transactions on Power Apparatus and Systems. Vol PAS-85.

ELCC of the renewable generator. It is important to note that the ELCC documents the capacity that achieves the same risk level as would be achieved without the renewable generator.

A graphical representation of ELCC appears in Figure 4. Adding the additional generation reduces the LOLP and shifts the reliability curve to the right. At the target of 1- day-in-10-years LOLE, the wind capacity value is 400 MW.

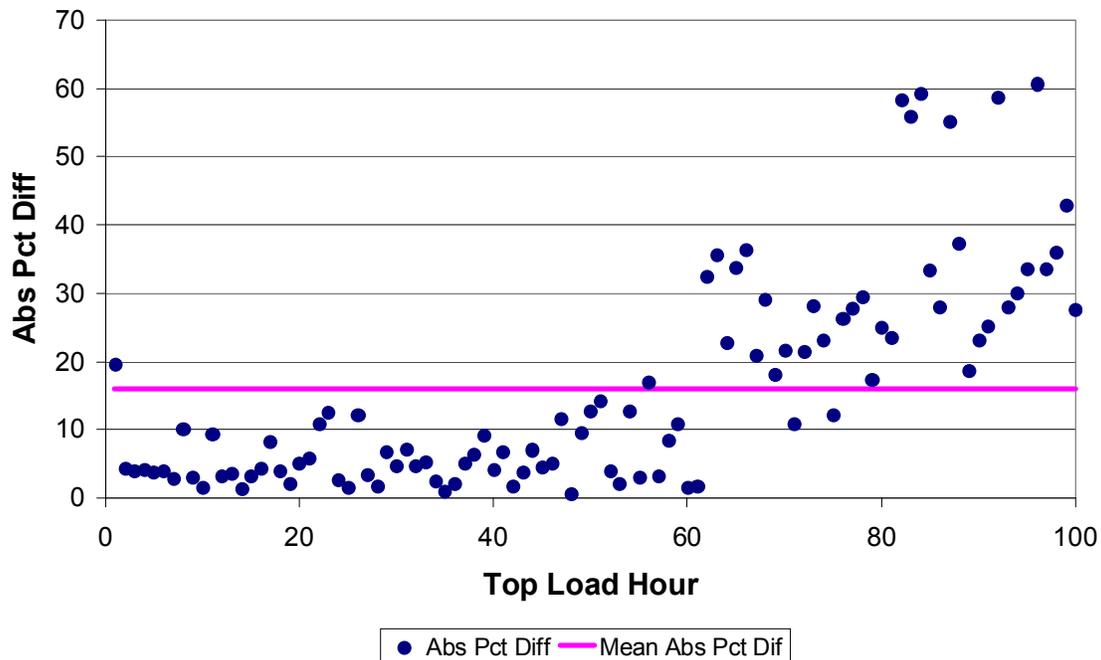


**Figure 4. ELCC is the vertical distance between the reliability curves, measured at the target reliability level (400 MW at 1d/10y).**

Because the LOLP in any given hour is a function of the load and available generation, it is subject to many influences that include the available online generation and their outage characteristics. When calculating the ELCC of a variable power plant such as wind, there are many hours with significant LOLP that drive the ELCC metric. The wind ELCC depends primarily on the relationship (correlation) between wind power and load, but other factors will also influence ELCC. Generation that is on maintenance is not available so will increase LOLP during those times. Controllable hydro generation is typically used to shave peak and/or is scheduled during periods of high prices. Peak periods are generally those periods with highest LOLP, but that is not always the case when hydro and maintenance schedules increase hourly LOLP during lower-load periods (an example of this is shown in Figure 5). Analysis that was

undertaken for the California Energy Commission<sup>6</sup> found that during an unusually late, hot summer period when many units were taken out of service for scheduled maintenance, the hourly LOLP in late September was nearly as high as during the peak summer period. Situations like this can result in a lack of recognition of the exposure of the power supply to potentially high levels of risk that can be overlooked. Any wind generation that would occur during these times would contribute to lowering LOLP, perhaps significantly.

## Hydro and No-Hydro LOLP



**Figure 5. The timing of other resources such as controllable hydro can have a significant impact on hourly LOLP, and therefore can influence ELCC of wind.**

Because LOLP and other reliability metrics are heavily influenced by the available generation, the transmission system plays a key role. In larger balancing areas, the grid allows the pooling of generation that can lower overall risk as measured by LOLP. Therefore, when investigating alternative transmission build-out scenarios or configurations, it is important to perform ELCC or LOLP evaluations *holding the transmission system configuration constant between the wind and no-wind cases*.

It is also important to distinguish between the capacity value of a generator and its schedule. During system-critical hours (generally defined as having a significant LOLP), it is possible that any given unit may be out of service as a result of mechanical or electrical failure. Achieving the desired reliability target such as 1d/10y alleviates, but does not eliminate the possibility that there are insufficient resources to serve load. A 1d/10y target implies that generation is sufficient

<sup>6</sup> California Renewable Portfolio Integration Standard Integration Cost Final Report. Henry Shiu, California Wind Energy Collaborative; Michael Milligan, National Renewable Energy Laboratory; Brendan Kirby, Oak Ridge National Laboratory; Kevin Jackson, Dynamic Design Engineering. California Energy Commission, 2006. Available at <http://www.energy.ca.gov/2006publications/CEC-500-2006-064/CEC-500-2006-064.PDF>

approximately 99.97% of the time, subject to the random and generally uncorrelated nature of unit outages. If 1d/10y is not judged to be a sufficient level of adequacy, then other more stringent targets could be adopted instead. Wind generation is subject to the same consideration. During some system-critical hours, wind may be producing output that is less than its ELCC. If proper risk-management and planning practices have been followed with a sufficient reliability target, this should pose no concern to system operations.

## Representing Wind in Reliability Models

The most straightforward way to represent wind is as an hourly modification to the load, using wind and load data from the same year, month, day, and hour. Some studies investigate the potential impact of future wind development scenarios on system reliability, operations, or economics. In those cases, the best approach is to use wind data from a numerical weather prediction (NWP) model that produces hourly or sub-hourly wind speed estimates that can be converted to realistic representations of large-scale wind power production. This approach is discussed further in Smith, et. al.<sup>7</sup> Multiple years of data is preferable to a single year because there is often significant inter-annual variability in wind ELCC from year to year. Examples are discussed later in this paper.

In Milligan and Porter (2005)<sup>8</sup>, we discussed probabilistic methods of representing wind in reliability models. Because of the evolution of NWP modeling techniques over the past few years, we do not recommend Monte Carlo approaches unless they have been successfully benchmarked against several years of actual wind data. We also caution that the Monte Carlo process that is built in to many reliability and production simulation models is likely to be inadequate for representing wind. This is because the Monte Carlo algorithms are typically based on probability distributions that do not adequately represent wind power and its changing distributions throughout the year.

In our earlier paper, we also discussed the erroneous use of percentiles to calculate wind capacity value. When representing wind in reliability models, we are aware of some cases where the wind capacity was input into the reliability model after first calculating a percentile level of wind. For example, if a 100-MW wind plant generated 10 MW or more 85% of the time, 10 MW would be entered into the model. That produces erroneous results because the reliability model can explicitly consider probabilities of alternative output levels when it calculates LOLE. This approach, if applied to conventional generation, such as that depicted in Figure 2 that has a forced outage rate greater than 15%, would result in a zero capacity value for that unit. We also showed in our 2005 paper that a system can achieve a reliability target even with units that have relatively high forced outage rates. That is also apparent in Figure 1 where we see that a larger planning reserve margin is necessary at higher forced outage rates to achieve the reliability target of 1d/10y.

---

<sup>7</sup> Smith, Milligan, DeMeo, and Parsons, "Utility Wind Integration and Operating Impact State of the Art," IEEE Transactions on Power Systems, Vol. 22, No. 3, August 2007.

<sup>8</sup> Milligan, M. and Porter, K. "Determining The Capacity Value Of Wind: A Survey Of Methods And Implementation," presented at WindPower 2005, Denver CO. Available at <http://www.nrel.gov/docs/fy05osti/38062.pdf>.

## Approximation Methods

Because of the potential difficulty of assembling the appropriate database to use for the ELCC calculation, interest in simpler methods has emerged over the past several years. To evaluate the capacity value of a wind plant, it would be desirable to have the ability to carry out the calculation using only the relevant wind data and whatever minimal auxiliary data set. Although several methods can be used to approximate ELCC, an unfortunate aspect of all of these methods is that they are indeed approximations. However, in cases where ELCC can't be calculated because of data or other limitations, these methods can be useful. In this section, we examine several techniques that we are familiar with. Other methods may exist or may be developed in the future.

Broadly speaking, the approximation techniques fall into two categories: risk-based or time-period-based. Risk-based techniques develop an approximation to the utility's LOLP curve throughout the year. Time-period-based methods attempt to capture risk indirectly, by assuming a high correlation between hourly demand and LOLP. Although this relationship generally holds, it can be compromised by scheduled maintenance of other units and hydro conditions. A further limitation of time-period-based methods is that all hours considered by the method are generally weighted evenly, whereas ELCC and other risk-based methods place greater weight on high-risk hours, and less weight on low risk hours. However, time-period based methods are much simpler, and are easy to explain in regulatory and other public proceedings. Milligan and Porter (2005) discussed risk-based simple methods; we will not repeat that discussion here.

To avoid using a reliability model altogether, it is possible to collect only hourly load and wind data for at least 1 year and use these data to calculate an approximation to ELCC. This approach is appealing in its simplicity, but it does not capture the potential system risks that are part of the other methods discussed above. Milligan and Parsons (1999) compared the ELCC with a series of calculations for hypothetical wind generation to determine whether these simpler approaches are useful. Although several alternative methods were compared, the most straightforward approach was to calculate the wind capacity factor (ratio of the mean to the maximum) over several times of high system demand. The calculations were carried out for the top 1% to 30% of loads, using an increment of 1%. Figure 6 is taken from that study. Although an ideal match was not achieved, the results show that at approximately 10% or more of the top load hours, the capacity factor is within a few percentage points of the ELCC. Many utilities, ISOs, and RTOs in the United States use time-period methods for assessing wind capacity value. We discuss those further below.

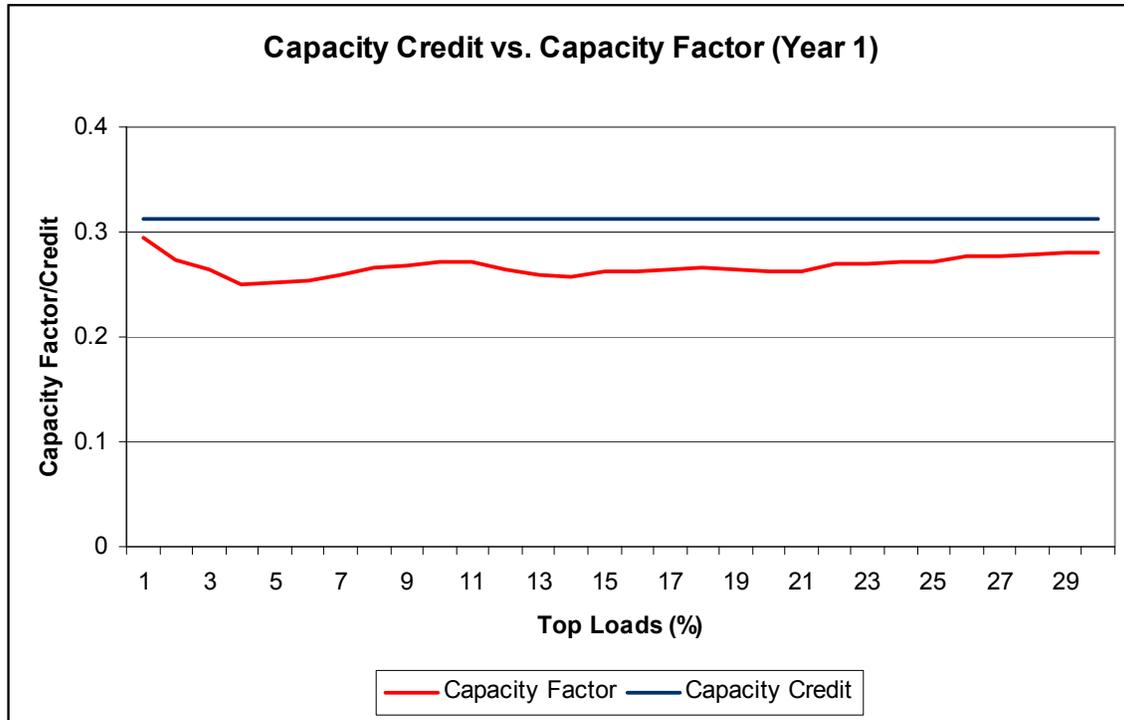


Figure 6. The capacity factor of wind during peak periods does not always match its ELCC value.

Some time-period methods succumb to the problem of using a percentile to calculate wind capacity value. This is a variation on our discussion above in the section Representing Wind in Reliability Models. For example, if the wind generation that occurs at least 85% of the time during a peak period is used for the capacity value, then all of the capacity generated that is below the percentile is excluded. The implication is that a forced outage rate (applied in the simplified method) that exceeds 15% does not have any contribution to system adequacy. That is also shown to be false in Figure 1. A similar argument can be made for other choices of the percentile. We note that the median value of a data series is the same as the 50<sup>th</sup> percentile; therefore, use of the median suffers from the same difficulty.

## Methods to Assess Wind Capacity Credit in the United States

In this section, we survey some of the approaches that are in use today to evaluate wind capacity credit. These methods come from a variety of entities, ranging from RTOs, public utility commissions, utilities, or studies carried out on behalf of these organizations.

### PJM Regional Transmission Organization

PJM is an RTO that encompasses all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia. PJM includes over 56,000 miles of transmission lines and more

than 1,200 generating units. PJM has almost 165,000 MW of capacity, and it serves about 145,000 MW of peak demand (PJM, 2007).

In general terms and on an annual basis, PJM requires load-serving entities (LSEs) to have a reserve margin of capacity above what is required to serve load. To meet that requirement, LSEs can self-supply capacity, enter into bilateral arrangements with generators for capacity and offering the capacity into PJM's forward capacity market, known as the Reliability Pricing Model (described more below). Alternatively, LSEs can pay the Locational Reliability Charges for their load obligations.

In 2007, PJM put in place a forward capacity market called the Reliability Pricing Model (RPM). This market includes an annual Base Residual Auction allowing LSEs to acquire power three years in advance of the delivery year, as well as three optional incremental auctions prior to the delivery year. In these auctions, LSEs meet their load obligations which are based on their respective shares of forecasted summer peaks and an additional 15% reserve margin.<sup>9</sup> RPM is meant to send price signals that will encourage the development of new capacity resources.<sup>10</sup>

Existing generators that participate in the capacity market must submit bids into the RPM auction, unless they have a committed sale outside of PJM. Those that do clear in the RPM auction, but produce less than bid, will either have to make it up through the bilateral market or incremental auctions, or pay for the shortfall of the higher of PJM's estimate of the cost of new entry or two times the RPM market clearing price.<sup>11</sup>

The capacity credit for wind in PJM is based on the wind generator's capacity factor during the hours from hours ending 3 p.m. to 6 p.m., local prevailing time, from June 1<sup>st</sup> through August 31<sup>st</sup>.<sup>12</sup> The capacity credit is a rolling 3-year average, with the most recent year's data replacing the oldest year's data. Because of insufficient wind generation data, PJM has applied a capacity credit "class average" of 20% for new wind projects, to be replaced by the wind generator's capacity credit as noted earlier once the wind project is in operation for at least a year. As an example, a new wind generator will receive a capacity credit of 20% the first year, and for the second year, the average of the wind generator's capacity factor during the hours from 3 p.m. to 7 p.m. from June 1 through August 31 and 20%, weighed twice since there is only one year of operational data. For the third year, a wind generator will receive the average of 20% and the wind generator's capacity factor during the hours from 3 p.m. to 7 p.m. for June 1 through August 31 for years two and three, and so on. In addition, wind generators that receive a capacity credit are required to bid into PJM's day-ahead energy market, along with other generators receiving capacity credit in PJM.

In May 2008, PJM replaced the 20% capacity credit class average with 13%, based on the average capacity factor during the 3 – 7 p.m. hours from June through August for all wind

---

<sup>9</sup> LSEs can opt to meet their required capacity obligation requirements through self-supply, subject to PJM approval and for a minimum period of five years.

<sup>10</sup> PJM. "Reliability Pricing Model." [www.pjm.com](http://www.pjm.com). (accessed 29 Jan 2008), <http://www.pjm.com/services/courses/c-reliability-pricing-model.html>

<sup>11</sup> For example, the cost of new entry in New Jersey is \$72,207/MW/year; \$74,117 MW/year in Maryland and \$73,866/MW/year in Illinois.

<sup>12</sup> PJM operates in both the Central and Eastern time zones.

generators that have been in operation for three years or more in PJM. The revised capacity credit will take effect for the 2011/12 period; the 20% class average will remain in effect until then. A higher project-specific capacity credit may be obtainable if the wind developer provides evidence that the wind turbine design and wind patterns justify the use of a higher capacity credit than the PJM class average for wind.<sup>13</sup>

PJM also sets minimum and maximum amounts that wind generators can bid into PJM's RPM auction, setting as a minimum of 85% of the capacity value of a wind project, and the maximum as the capacity value of either the individual wind generator (if more than three years of operational experience is available), or the capacity credit class average for wind at the time of the auction. Considering a 100-MW wind project, for example, then the maximum it can bid into the RPM auction is 13 MW ( $0.13 \times 100$ ), and the minimum is 11.05 MW ( $0.85 \times 13$ ). The 15% approximately represents the standard deviation from the mean of the annual capacity value of wind generators now operating in PJM. The minimum and maximum bid amounts for wind were implemented in order for wind generators to minimize the potential for being penalized for under-delivering, such as lower-than-expected wind resource patterns.<sup>14</sup>

## **New York ISO**

The New York ISO (NYISO) consists of the transmission assets of eight transmission owners located in New York and a small part of New Jersey. The NYISO includes about 43,771 MW of available capacity (including in-state and out-of-state capacity and demand response resources) and had a peak load of 32,169 MW in 2007.<sup>15</sup> The NYISO also requires LSEs to have capacity reserves over their load requirements.

The NYISO has a capacity market and obtains capacity through three auctions: a 6-month strip auction held twice a year, prior to the summer and winter capability periods; a series of monthly auctions; and a monthly spot auction for LSEs that have not met their reserve obligations. The summer capacity credit for existing wind projects is determined by a wind project's capacity factor between 2 p.m. and 6 p.m. during June, July, and August from the year before. A winter capacity credit for wind is determined by the capacity factor of wind between the hours of 4 p.m. and 8 p.m. during December, January, and February from the year before. New wind projects are assigned a summer capacity credit of 10% and a winter capacity credit of 30% of their nameplate capacity. In addition, variable energy generators such as wind are exempt from having to bid into the day-ahead energy market in the NYISO, a requirement for other non-variable energy generators.

---

<sup>13</sup> PJM. *PJM Manual 21: Rules and Procedures for Determination of Generating Capability*. April 1, 2008. <http://www.pjm.com/contributions/pjm-manuals/pdf/m21.pdf>. (accessed April 11, 2008).

<sup>14</sup> PJM RPM Working Group. *Offering Wind Resources in RPM Auctions*. January 22, 2008. <http://www.pjm.com/committees/working-groups/rpmwg/downloads/20080122-item-03-offering-wind-resources.pdf>. (accessed April 10, 2008).

<sup>15</sup> New York ISO. *Summer 2007 Electricity Review*. October 2007. [http://www.nyiso.com/public/webdocs/newsroom/press\\_releases/2007/summer\\_2007\\_electricity\\_review\\_102507.pdf](http://www.nyiso.com/public/webdocs/newsroom/press_releases/2007/summer_2007_electricity_review_102507.pdf). (accessed April 10, 2008).

## ISO New England

ISO New England operates in six states and includes more than 34,000 MW of capacity and serves about 27,000 MW of load.<sup>16</sup> ISO New England has changed from an installed capacity market to a forward capacity market auction, as described below.

Wind generators under 5 MW in capacity participate in the ISO New England energy market as “settlement only” resources, a category for generating resources under 5 MW. Settlement-only resources sell electricity into the grid at real time and receive the real-time market clearing price. Wind generators over 5 MW would be classified as variable power resources and can schedule into the ISO New England’s day-ahead market. If variable power resources do not submit bids into the day-ahead market, then before the next operating day, these resources must self-schedule the capacity amount for each hour. If in real time the capacity amount is different than the self-schedule amount, the variable power resource must contact the ISO and re-declare its schedule.

As with PJM, ISO New England administers a forward capacity market, with an annual auction set three years before actual delivery is due. All demand and supply resources can participate in a descending clock auction to meet ISO New England’s installed capacity requirement. The results of the first auction were announced in early 2008. Over 39,000 MW of new and existing generating resources competed for the projected 32,305 MW of load in the 2010 to 2011 timeframe.<sup>17</sup> A second auction is scheduled for December 2008.

New variable energy projects, including wind, that wish to participate in the forward capacity market auction can claim a summer and winter capacity credit, but must provide at least one year’s worth of supporting summer and winter wind speed data for wind; water flow data for run-of-the-river hydro; and irradiance data for solar facilities. ISO New England and a consultant will verify the information. Actual data will be used to adjust the capacity credit once the variable energy project is in operation. Should actual capacity levels fall below the capacity credit by at least 20% or 40 MW, the generator must cover the deficit or submit a plan to increase capacity.<sup>18</sup>

For determining the summer capacity credit for existing variable energy projects, ISO New England, for the first forward capacity market auction, took the average of the median net output of the variable renewable energy from 2:00 p.m. through 6:00 p.m. from June through September for the previous four years. The same terms apply for subsequent forward-capacity market auctions, except that ISO New England will use five years instead of four. Also, after June 2010, variable energy resources will also receive capacity credit during summer peak hours when ISO New England has declared a system-wide shortage. Furthermore, if the variable energy resource

---

<sup>16</sup> ISO New England. *2007-2016 Forecast Report of Capacity, Energy, Loads, and Transmission*. April 2007. Available at:

[http://www.iso-ne.com/trans/celt/report/2007/2007-celt\\_report.pdf](http://www.iso-ne.com/trans/celt/report/2007/2007-celt_report.pdf) (accessed January 29, 2008).

<sup>17</sup> ISO New England. “Wholesale Marketplace Helping to Achieve Long-term Power System Reliability Goals.” February 13, 2008. [http://www.iso-ne.com/nwsiss/pr/2008/press\\_release\\_fcm\\_auction\\_results\\_02\\_13\\_08.pdf](http://www.iso-ne.com/nwsiss/pr/2008/press_release_fcm_auction_results_02_13_08.pdf) (accessed April 10, 2008).

<sup>18</sup> Abigail Krich. *Wind Energy’s Role in the New England Forward Capacity Market*. Poster Presentation at WindPower 2008, June 2-4, 2008, Houston, Texas.

is in an import-constrained capacity zone, then capacity credit will be granted for all shortage events in that zone. All existing resources, whether wind or non-wind, are price takers in the auction and will clear unless they de-list from the auction.

ISO New England also provides a winter capacity credit for existing variable energy generators for the median output between 6:00 p.m. and 7:00 p.m. between October and May for the past four years for the 2007 forward-capacity market auction, five years thereafter.<sup>19</sup> As with the provisions for summer capacity credit, additional capacity credit may be available after June 2010, if ISO New England has declared a system-wide shortage event, and partial years will be used to determine a variable generator's capacity credit.<sup>20</sup>

## **Southwest Power Pool**

The Southwest Power Pool (SPP) adopted a method to calculate wind capacity contribution (SPP Generation Work Group, 2004). The SPP uses a monthly method that results in 12 capacity measures for the wind plant. The process first examines the highest 10% of load hours in the month. Wind generation from those hours is then ranked from high to low. The wind capacity value is selected from this ranking, and it is the value that is exceeded 85% of the time (the 85<sup>th</sup> percentile). Up to 10 years of data are used if available. For the wind plants studied in the SPP region, the capacity values are typically about 10% rated capacity.<sup>21</sup> According to SPP's Generation Working Group (SPP GWG) presentation, this method is used for long-term planning. Although it appears counter-intuitive to us, the SPP GWG believes that ELCC/LOLP methods are better used to determine the level of desired spinning or operating reserves and not to determine the reliability impacts of wind.

## **Minnesota Department of Commerce/Xcel**

The Minnesota Department of Commerce (MN/DOC) study examined the impact of 1,500 MW of wind capacity distributed at various locations in southwest Minnesota. This represents approximately 15% wind penetration, based on the ratio of rated wind capacity to peak load. One of the tasks of this study was to calculate the capacity contribution of wind. The study used a Sequential Monte Carlo method, which performed repeated sampling of an annual state transition matrix that was calculated based on the wind data used in the study. The intent of this approach is to capture some of the impact of inter-annual variation of wind so that estimates of ELCC may be more robust. The SMC cases found a 26.7% capacity contribution for prospective wind plants. For comparison, the study also used a simple "load-modifier" method that calculates

---

<sup>19</sup> If an intermittent energy resource has a summer capacity value of zero but has a positive winter capacity value, the intermittent energy resource will be placed in the forward capacity market auction to ensure payment for the winter capacity contribution. Only intermittent resources are eligible for this treatment. Personal Communication, Mark Tessicini, ISO New England, June 12, 2008.

<sup>20</sup> ISO New England. *Market Rule 1*. April 3, 2008. [http://www.iso-ne.com/regulatory/tariff/sect\\_3/index.html](http://www.iso-ne.com/regulatory/tariff/sect_3/index.html). (accessed April 10, 2008).

<sup>21</sup> See, for example, the discussion in Westar's Energy Plan. Westar Energy. *Meeting Our Customers' Energy Needs: A Strategic Plan for Uncertain Times*. Undated. [http://www.westarenergy.com/corp\\_com/contentmgt.nsf/resources/CEP/\\$File/CEP.pdf?openement](http://www.westarenergy.com/corp_com/contentmgt.nsf/resources/CEP/$File/CEP.pdf?openement). (accessed April 10, 2008).

reliability based on a simple netting of the wind generation against hourly load. When this approach was used, the prospective wind capacity value was 32.9% of rated capacity.

Another study, conducted by the EnerNex Corporation in November, 2006, on behalf of the Minnesota Public Utilities Commission, analyzed the effect of 15%, 20%, and 25% wind penetration levels on the Minnesota Electricity grid using wind data from 2003, 2004, and 2005. Using 2004 as a base year, the study found that a 25% wind penetration level would only require an increase in reserve requirements from 5% to 7.05%. The study also estimated capacity values of wind generation using an ELCC/LOLP method, finding it to be between 5% and 20% of nameplate capacity depending on penetration level and wind year.<sup>22</sup>

## **PacifiCorp**

PacifiCorp recently completed a new Integrated Resource Plan (IRP).<sup>23</sup> In the plan, PacifiCorp used ELCC as the standard calculation of capacity contribution from wind generation for planning purposes. Wind generation was modeled using the same Sequential Monte Carlo approach used by EnerNex in the Minnesota DOC study. For the several prospective wind locations analyzed by PacifiCorp, the capacity contribution of wind averaged approximately 20% of rated capacity. The capacity value from the IRP is used as part of an evaluation to determine how much additional capacity is needed to meet future load forecasts.

## **Electric Reliability Council of Texas (ERCOT)**

ERCOT evaluated the operating wind plants to determine the capacity contribution of wind. The analysis was based on wind generation on weekdays from 4:00 p.m. to 6:00 p.m. during July and August, the peak period for ERCOT. Using historical data and an adjustment for Equivalent Forced Outage Rate for a combustion turbine and a confidence factor, ERCOT calculated a factor of 2.9% of nameplate capacity. Beginning in 2005, this factor is used to include wind power in reserve margin calculations. The method of evaluation of this confidence factor is unclear from the document. ERCOT's Generation Adequacy Task Force recently made a recommendation to alter the capacity contribution factor suggesting a number of new methodologies which would raise the capacity contribution factor from 5.3% to 16.3%. The task force concluded that "the ELCC methodology should be used until better (i.e., more) actual performance data becomes available to make an accurate determination of the true capacity value of wind in ERCOT."<sup>24</sup>

Unfortunately, the ERCOT approach utilized data from a long-term NWP model that did not retain the synchronization between the load and wind. As described by the ERCOT documents,

---

<sup>22</sup> EnerNex Corp. *2006 Minnesota Wind Integration Study*. November 30, 2006.

[http://www.enernex.com/staff/docs/windrpt\\_vol%201.pdf](http://www.enernex.com/staff/docs/windrpt_vol%201.pdf) and

[http://www.enernex.com/staff/docs/windrpt\\_vol%202.pdf](http://www.enernex.com/staff/docs/windrpt_vol%202.pdf) (accessed January 30, 2008).

<sup>23</sup> PacifiCorp. *2007 Integrated Resource Plan*. May 2007. <http://www.utahpower.net/File/File74765.pdf> (accessed January 30, 2008).

<sup>24</sup> Electric Reliability Council of Texas' Generation Adequacy Task Force. *Recommended Changes to the ERCOT Reserve Margin Calculation Methodology*. March 7, 2007.

[http://www.ercot.com/meetings/tac/keydocs/2007/0330/11\\_Draft\\_GATF\\_Report\\_to\\_TAC\\_-\\_Revision\\_2.doc](http://www.ercot.com/meetings/tac/keydocs/2007/0330/11_Draft_GATF_Report_to_TAC_-_Revision_2.doc) (accessed January 31, 2008).

the wind data was not coincident with load data. In fact, the wind data was chosen based on a random selection of a 24-hour period. Although this represents an improvement over past methods, contemporary work on wind integration and capacity value has stressed the use of time-coincident wind and load data so that underlying weather patterns are picked up by the data set.

## **Mid-Continent Area Power Pool (MAPP)**

The Mid-Continent Area Power Pool (MAPP) approach is a monthly method that calculates wind capacity value based on the timing of its delivery relative to peak. Up to 10 years of data (wind and load) can be used if available. For each month, a 4-hour time window surrounding the monthly peak is selected. Any contiguous 4-hour period can be selected, as long as the peak hour falls within the window. The wind generation data from that 4-hour period in all days of the month are then sorted, and the median value is calculated. The median value is wind's capacity value for the month. If multiple years of data are available, the process is carried out on the multi-year data set. The results of these calculations are used in operational planning in the power pool.

## **Nebraska Public Power District**

The Nebraska Public Power District (NPPD) serves nearly a million Nebraska customers. In 2006, it completed construction on its 36-turbine, 60-MW Ainsworth wind farm. NPPD assigns a capacity credit of 17% of nameplate capacity to wind energy. Little information was provided on how this capacity credit was determined. NPPD's draft 2008 IRP calls for completing negotiations of a power purchase agreement for up to 150 MW of wind by 2008 or 2009; build or contract for another 100 to 150 MW of wind power for 2014 to 2016; conduct a wind integration study; and perform a study on how much transmission is necessary to facilitate major development of new wind generation in Nebraska.<sup>25</sup>

## **Idaho Power**

According to its 2006 IRP, Idaho Power gives wind a 5% capacity credit, based on a 100-MW wind plant's projected output that would occur 70% or more of the time between 4:00 p.m. and 8:00 p.m. during July, Idaho Power's peak month.<sup>26</sup> Therefore, Idaho Power's method is similar to SPP's by multiplying a subjective statistical number by actual capacity factor values.

## **Pacific Northwest**

The Northwest Resource Adequacy Forum, an initiative of Bonneville Power Administration and the Northwest Power and Conservation Council, are working to create a consensus-based resource adequacy framework for the Pacific Northwest. The Forum assigned a proxy capacity

---

<sup>25</sup> Nebraska Public Power District. *2008 Integrated Resource Plan (Draft)*. [http://www.nppd.com/irp/additional\\_files/irp\\_draft.pdf](http://www.nppd.com/irp/additional_files/irp_draft.pdf). (accessed April 10, 2008).

<sup>26</sup> Idaho Power. *2006 Integrated Resource Plan*. October 12, 2006. [http://www.idahopower.com/pdfs/energycenter/irp/2006/2006\\_IRP.pdf](http://www.idahopower.com/pdfs/energycenter/irp/2006/2006_IRP.pdf). (accessed January 30, 2008).

credit of 15% for wind. However, a recommendation of the Northwest Wind Integration Action Plan is to reassess that proxy value, and the Forum is in the process of doing so.

## California

The California Public Utilities Commission (CPUC) has a local resource adequacy requirement that requires load-serving entities under the CPUC's jurisdiction to provide evidence that at least 90% of the capacity needed to meet demand is available, plus a planning reserve margin of 15% to 17%, on a year-ahead basis for the following May through September. The CPUC determines these capacity obligations annually and has just started a new proceeding for determining resource adequacy requirements for 2009.<sup>27</sup>

The monthly net qualifying capacity credit of wind is determined by the three-year average of monthly hourly production between noon and 6:00 p.m. on weekdays. Therefore, for June 2007, the monthly capacity credit would be determined by the average of monthly hourly wind generation for June 2004, June 2005 and June 2006.<sup>28</sup> For wind projects with less than three years of operation, a "class average" of all wind generation within a transmission zone will be used, supplemented with project-specific data when available.<sup>29</sup>

A CPUC staff paper determined that the monthly net qualifying capacity value of wind in summer 2007 ranged from 20% to 60% of nameplate capacity in June, to between 15% and 30% in July and August. There also was considerable variation between the different wind development areas in California, with Tehachapi in southern California generally having the highest ratio of net qualifying capacity to nameplate, and Solano in northern California having the lowest, but with Solano producing the highest fraction of its net qualifying capacity during summer peak hours.<sup>30</sup>

## PNM

Public Service of New Mexico (PNM) provides power for 1.3 million customers from its eight power plants, including the New Mexico Wind Energy Center, and from the wholesale market. PNM examined wind's contribution during its peak time of between 4:00 p.m. and 5:00 p.m. during July for the 200-MW New Mexico Wind Energy Center project. PNM determined that the wind plant was at 1 – 5 MW 16% of the time, followed by 0 MW, 6 – 10 MW, 11 – 15 MW and 16 – 20 MW, each close to 8% of the time. PNM determined that the most capacity wind

---

<sup>27</sup> California Public Utilities Commission. *Order Instituting Rulemaking to Consider Annual Revisions to Local Procurement Obligations and Refinements to the Resource Adequacy Program*. Rulemaking 08-01-025, February 22, 2008.

<sup>28</sup> California Public Utilities Commission. *Order Instituting Rulemaking to Promote Policy and Program Coordination and Integration in Electric Utility Resource Planning*. D.05-10-042, October 27, 2005. [http://docs.cpuc.ca.gov/word\\_pdf/FINAL\\_DECISION/50731.pdf](http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/50731.pdf) (accessed April 9, 2008).

<sup>29</sup> California Public Utilities Commission. *Order Instituting Rulemaking to Consider Refinements to and Further Development of the Commission's Resource Adequacy Requirements Program*. D.07-06-029, June 21, 2007. [http://docs.cpuc.ca.gov/WORD\\_PDF/FINAL\\_DECISION/69513.PDF](http://docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/69513.PDF) (accessed April 9, 2008).

<sup>30</sup> California Public Utilities Commission Staff Report. *2007 Resource Adequacy Report*. March 20, 2008.

can provide is less than 1 MW (16%\*5 MW). Therefore, PNM concluded wind cannot be assigned a capacity credit at this time.<sup>31</sup>

## Tri-State Generation and Transmission

The Energy Policy Act of 1992 requires customers of the Western Area Power Administration, such as Tri-State Generation and Transmission, to file an IRP every five years. For its 2007 IRP, Tri-State compared monthly on-peak, off-peak, and average capacity factors for wind projects in southeastern Colorado. Tri-State noted that the capacity factors for wind from May through August are lower than in other months, and determined that the capacity value of wind, as measured by wind's contribution to Tri-State's monthly coincidental peak, ranges from 2% to 12%.<sup>32</sup>

## Colorado PUC/Xcel Energy

Xcel Energy issued an ELCC study in 2007, as required via a settlement Xcel entered into with several parties. The company used hourly wind energy production profiles for 1996 through 2005 for several locations in eastern Colorado; historical loads from 1996 to 2005; forecasted load from 2008 through 2012; planned maintenance schedules and plant outage rates. Xcel modeled three scenarios of 280, 755, and 1,035 MW of wind, respectively. Unfortunately, the modeling software adjusted the 1996 – 2005 load data to meet projected monthly peak demand for 2008 through 2012. That, in turn, disconnected the load profiles from the wind profiles, affecting the final results and causing the ELCC values for wind to vary dramatically from scenario to scenario, and from year to year. Ultimately, Xcel Energy recommended adopting a capacity credit of 12.2% for wind.<sup>33</sup> In its 2007 IRP plan, Xcel Energy used 12.5% capacity credit for wind.<sup>34</sup>

## Summary of Time Period Approximation Methods Used in the United States

Figure 7 shows the time periods used by some of these approximation methods. What is clear in each case is that the utility, ISO, or RTO used time periods that are reflective of the peak load period.

---

<sup>31</sup> Public Service Company of New Mexico. *2007 Electric Resource Plan*. February 8, 2007.

[http://www.pnm.com/regulatory/pdf\\_electricity/irp\\_electric\\_resource\\_plan.pdf](http://www.pnm.com/regulatory/pdf_electricity/irp_electric_resource_plan.pdf) (accessed February 1, 2008).

<sup>32</sup> Tri-State Generation and Transmission Association, Inc. *Integrated Resource Plan*. February 15, 2007.

<http://www.tristategt.org/NewsCenter/NewsItems/Tri-State%20IRP%2002-15-2007.pdf>. (accessed April 9, 2008).

<sup>33</sup> Xcel Energy. *An Effective Load Carrying Capability Study for Estimating the Capacity Value of Wind Generation Resources*. March 1, 2007. <http://www.xcelenergy.com/docs/PSCoELCCFinalReport030107.pdf> (accessed April 11, 2008).

<sup>34</sup> Xcel Energy. *2007 Colorado Resource Plan*. November 15, 2007.

[http://www.xcelenergy.com/XLWEB/CDA/0.3080.1-1-1\\_41994\\_48216\\_48221-42116-0\\_0\\_0-0.00.html](http://www.xcelenergy.com/XLWEB/CDA/0.3080.1-1-1_41994_48216_48221-42116-0_0_0-0.00.html). (accessed April 11, 2008).

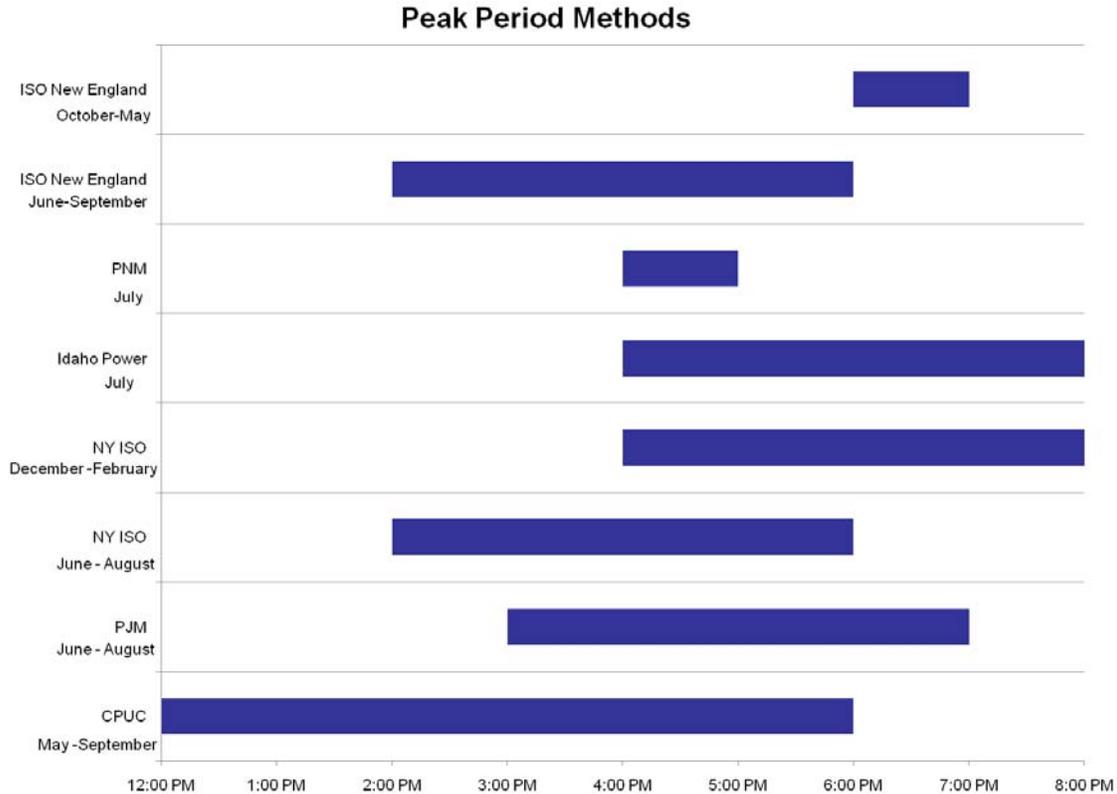


Figure 7. Selected time periods used for ELCC approximation methods in the U.S.

### Inter-annual Variability of Wind: Influence on ELCC

To provide examples of how ELCC values can change from year to year, we show the impact from two studies: The California Wind Energy Collaborative (CWEC)/California Energy Commission Report<sup>35</sup> and the Minnesota 20% Wind Integration Study<sup>36</sup>. The CWEC project calculated the ELCC for wind in California for a 3-year period, and looked at three wind regions within the state. Because of the characteristics of the thermally-driven wind that spills over the mountain passes in many afternoons, this pattern results in a relatively stable ELCC. These results appear in Figure 8. Although there is a difference in the ELCC for San Geronio, the other sites show little change from year to year. The CWEC study also compared 3-year average ELCC with 3-year average capacity factor between June and September, 12:00 p.m. to 6:00 p.m. (the peak period as defined by the CA ISO). Figure 9 shows that these averages were very close in two of the three regions.

<sup>35</sup> H. Shiu, M. Milligan, B. Kirby, and K. Jackson, California Renewables Portfolio Standard, Renewable Generation Cost Analysis: Multi-Year Analysis Results and Recommendations, California Wind Energy Collaborative for the California Energy Commission. Sacramento, CA, Jun. 2006, accessed Nov. 17, 2006. [Online]. Available: <http://www.energy.ca.gov/2006publications/CEC-500-2006-064/CEC-500-2006-064.PDF>

<sup>36</sup> R. Zavadil, J. King, N. Samaan, J. Lamoree, "Final Report - 2006 Minnesota Wind Integration Study Volume I", EnerNex Corporation and WindLogics, Inc., Nov 30, 2006. Accessed Jan 18, 2008, [Online] Available: [http://www.uwig.org/windrpt\\_vol%201.pdf](http://www.uwig.org/windrpt_vol%201.pdf)

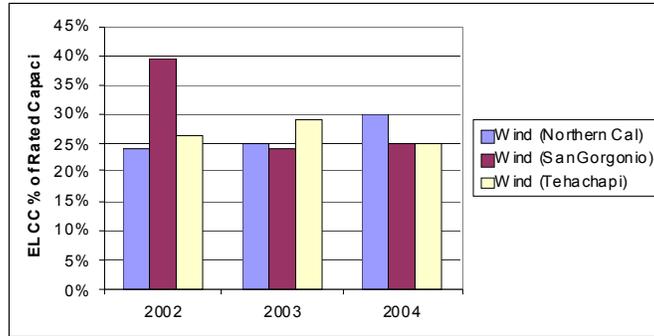


Figure 8. Capacity value of wind in California generally shows low variation from year to year.

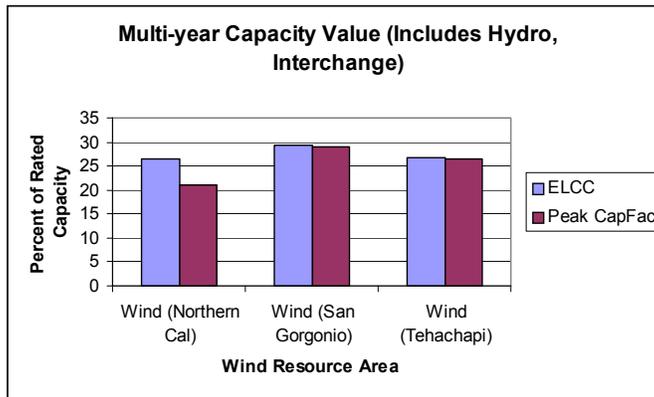


Figure 9. 3-year effective load carrying capability in California did not always match wind capacity factor over peak hours.

The Minnesota results over a 3-year period are strikingly different. Figure 10 shows that the ELCC value for each of the capacity penetrations were quite different. The explanation for this variation appears to be the significantly different weather patterns, particularly in 2005, which influenced wind during system-critical times.

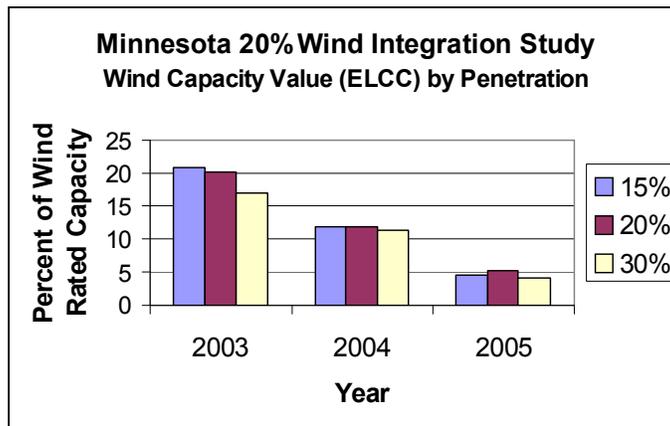


Figure 10. Minnesota multi-year ELCC results at different wind penetrations.

## **Summary of Study Results**

We have chosen the results from several recent studies to illustrate the range of capacity values found to apply to wind. A more complete summary of wind capacity value appears in Table 1 (following page). Most approaches use either ELCC or a time-period basis to calculate wind capacity factor. Just as conventional generators with high forced outage rates have lower ELCC values relative to rated capacity, we can conclude that wind generators also have different ELCC values relative to their rated capacity. This should be no surprise. The wind resource varies significantly around the United States. The ELCC of wind depends heavily on its correlation with load during high-risk and high LOLP periods.

**Table 1. Wind Capacity Value in the United States.**

<b>Region/Utility</b>	<b>Method</b>	<b>Note</b>
CA/CEC	ELCC	Rank bid evaluations for RPS (mid 20s); 3-year near-match capacity factor for peak period used by CA PUC and CA ISO
CPUC	Peak Period	Three-year rolling average of the monthly average of wind energy generation between 12 and 6 p.m. for the months of May through September.
PJM	Peak Period	Jun-Aug HE 3 p.m. -7 p.m., local time, capacity factor using 3-year rolling average (13%, fold in actual data when available).
MN 20% Study	ELCC	Found significant variation in ELCC: 4%, 15%, 25% and variation based on year
ERCOT	ELCC	ELCC based on random wind data, compromising correlation between wind and load (8.7%)
MN/DOC/Xcel	ELCC	Sequential Monte Carlo (26-34%)
NY ISO	Peak Period	Wind's capacity factor between 2-6 p.m., June through August, and 4-8 p.m., December through February
CO PUC/Xcel	ELCC	12.5% of rated capacity based on 10-year ELCC study. Load forecast algorithm compromised correlation between wind and load
PacifiCorp	ELCC	Sequential Monte Carlo (20%). Z-method 2006
MAPP	Peak Period	Monthly 4-hour window, median
Idaho Power	Peak Period	4 p.m. - 8 p.m. capacity factor during July (5%)
Nebraska Public Power District		17% (method not stated)
Northwest Resource Adequacy Forum	Rule of Thumb	15%. Being studied further for potential revision.
Tri-State	Peak Period	2-12%. Appears to be based on wind's contribution to monthly coincidental peak.
SPP	Peak Period	Top 10% loads/month; 85th percentile
PNM	Peak Period	Capacity factor between 4-5 p.m. in July
ISO New England	Peak Period	For existing wind: wind's capacity factor between 2-6 p.m., June through September and 6-7 p.m. from October through May. For new wind: based on summer and winter wind speed data, subject to verification by ISO New England and adjusted by operating experience.

## Wind Capacity Value in Europe

A recent International Energy Agency report was released with the details wind integration impacts from actual experience and studies from the United States and Europe.<sup>37</sup> The report discusses ELCC, and concludes “We therefore recommend that a reliability-based metric should be used to address wind capacity value.”

A recent literature review conducted by the United Kingdom Energy Research Center (UKERC) summarized wind capacity contributions to system adequacy. The report discusses LOLP-based capacity valuation and presents results from 29 studies that performed capacity assessments of wind. All of the cited studies used approaches based on LOLP. Figure 10 illustrates the results. Details can be found in the original report.<sup>38</sup>

Figure 11, also taken from the UKERC study, tabulates the results of the various studies and the capacity credit calculated as a percentage of rated capacity.

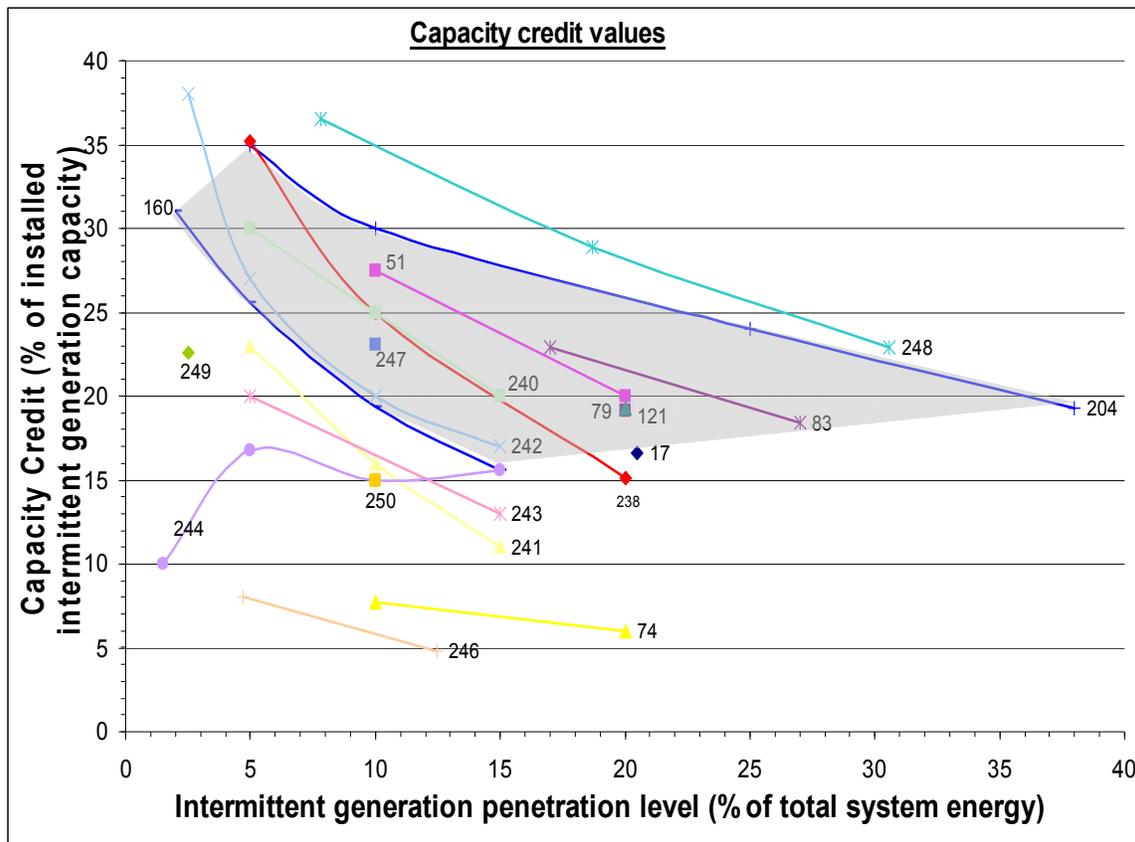


Figure 10. Range of wind capacity values in the UKERC report. Details can be found in the original report.

<sup>37</sup> Hannele Holttinen. *Design and Operation of Power Systems with Large Amounts of Wind Power: State-of-the-Art Report*. International Energy Agency, October 2007. <http://www.vtt.fi/inf/pdf/workingpapers/2007/W82.pdf>.

<sup>38</sup> Robert Gross, Philip Heptonstall, Dennis Anderson, Tim Green, Matthew Leach and Jim Skea. *The Costs and Impacts of Intermittency: An Assessment of the Evidence on the Costs and Impacts of Intermittent Generation on the British Electricity Network*. United Kingdom Energy Research Centre, March 2006. [http://www.uwig.org/0604/Intermittency\\_report\\_final.pdf](http://www.uwig.org/0604/Intermittency_report_final.pdf).

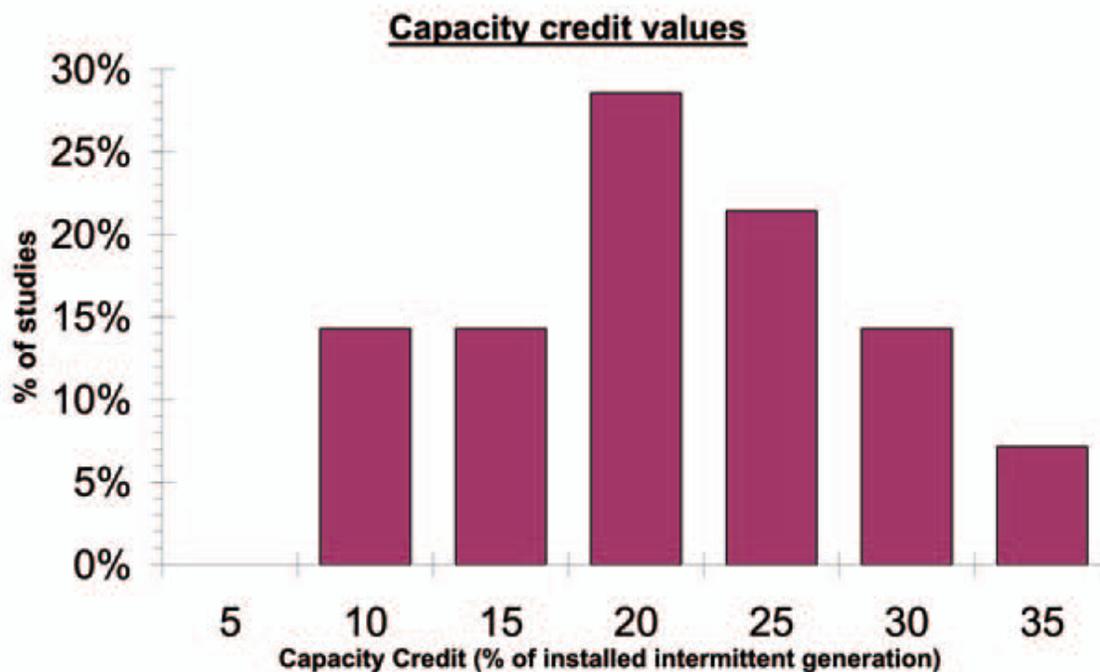


Figure 11. UKERC study tabulated the results of the various wind capacity value results.

## Assessment and Recommendations

A reliability-based adequacy metric is the most rigorous and appropriate for capacity credit determination because it directly ties to system adequacy. Planning reserve margin percentages must be benchmarked or derived from probabilistic studies to have meaning. ELCC and related approaches appear to be gaining more interest, both in the United States and in Europe. Although we have not been explicit on this point: ELCC can, and should, also be applied to conventional generators. Capacity from *any* generator at some time in the future is not guaranteed. Because all generators are subject to outage, even during system-critical times, a probabilistic approach to calculating capacity value is appropriate. This is especially true for variable resources such as wind power plants. Because of the stochastic nature of the wind, and therefore wind energy, a method that can explicitly quantify the risks associated with this resource is critical. Standard power system reliability theory exists that can be used for this purpose.

When a reliability-based approach is used to calculate the capacity credit of wind power plants, risk is explicitly embodied in the calculation. The ELCC method is rigorous, data-driven, and can finely distinguish among generators that have different impacts on system reliability. However, the method requires datasets that are not always available and is influenced by many system characteristics. For these reasons and others, simplified methods have been developed. These methods are sometimes based on wind generation during a time period that corresponds to high system risk hours. In other cases, methods can approximate the system LOLP curve so that high-risk hours receive more weight than other hours. We favor experimentation with such methods, but suggest that it would be helpful to benchmark simple methods against ELCC. This

will help eliminate the sometimes arbitrary assumptions that can be introduced by some simple calculations we have encountered.

Inter-annual variability of wind generation is an important issue, and it can have an effect on any capacity metric. We recommend that multiple years of data be used in capacity value calculations. If that is not possible, we think that several approaches covered in this paper can be useful. Going forward, we expect that the capacity value of wind generating plants will continue to be a topic that receives significant attention. We encourage open analysis and reporting of the findings that increasing experience with wind will bring.

As a practical matter, the capacity value of any power plant should be based on actual performance. To this end, we suggest that existing wind plants should be subject to on-going evaluation. An approach that calculated the most recent 3-year rolling average of capacity value, such as used by PJM, is very useful. This approach can be used with a reliability-based metric such as ELCC (our preference), but can also be applied to simpler methods.

Finally, although most of our discussion on ELCC has centered on LOLE as the reliability metric, there may be other reliability measures that would also be useful. In particular, expected unserved energy measures not only the probability of shortfall, but also measures the extent of the shortfall. We encourage further analysis and refinements as more wind is installed across the country.

# REPORT DOCUMENTATION PAGE

Form Approved  
OMB No. 0704-0188

The public reporting burden for this collection of information is estimated to average 1 hour per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to Department of Defense, Executive Services and Communications Directorate (0704-0188). Respondents should be aware that notwithstanding any other provision of law, no person shall be subject to any penalty for failing to comply with a collection of information if it does not display a currently valid OMB control number.

**PLEASE DO NOT RETURN YOUR FORM TO THE ABOVE ORGANIZATION.**

<b>1. REPORT DATE (DD-MM-YYYY)</b> June 2008		<b>2. REPORT TYPE</b> Conference Paper		<b>3. DATES COVERED (From - To)</b> June 2008		
<b>4. TITLE AND SUBTITLE</b> Determining the Capacity Value of Wind: An Updated Survey of Methods and Implementation: Preprint				<b>5a. CONTRACT NUMBER</b> DE-AC36-99-GO10337		
				<b>5b. GRANT NUMBER</b>		
				<b>5c. PROGRAM ELEMENT NUMBER</b>		
<b>6. AUTHOR(S)</b> M. Milligan and K. Porter				<b>5d. PROJECT NUMBER</b> NREL/CP-500-43433		
				<b>5e. TASK NUMBER</b> WER8.5001		
				<b>5f. WORK UNIT NUMBER</b>		
<b>7. PERFORMING ORGANIZATION NAME(S) AND ADDRESS(ES)</b> National Renewable Energy Laboratory 1617 Cole Blvd. Golden, CO 80401-3393				<b>8. PERFORMING ORGANIZATION REPORT NUMBER</b> NREL/CP-500-43433		
<b>9. SPONSORING/MONITORING AGENCY NAME(S) AND ADDRESS(ES)</b>				<b>10. SPONSOR/MONITOR'S ACRONYM(S)</b> NREL		
				<b>11. SPONSORING/MONITORING AGENCY REPORT NUMBER</b>		
<b>12. DISTRIBUTION AVAILABILITY STATEMENT</b> National Technical Information Service U.S. Department of Commerce 5285 Port Royal Road Springfield, VA 22161						
<b>13. SUPPLEMENTARY NOTES</b>						
<b>14. ABSTRACT (Maximum 200 Words)</b> This paper summarizes several important state and regional studies that examine the capacity value of wind energy, how different regions define and implement capacity reserve requirements across the country, and how wind energy is defined as a capacity resource in those regions.						
<b>15. SUBJECT TERMS</b> Wind; integration; wind integration; capacity value; electric utilities; ISO; RTO						
<b>16. SECURITY CLASSIFICATION OF:</b>			<b>17. LIMITATION OF ABSTRACT</b> UL	<b>18. NUMBER OF PAGES</b>	<b>19a. NAME OF RESPONSIBLE PERSON</b>	
<b>a. REPORT</b> Unclassified	<b>b. ABSTRACT</b> Unclassified	<b>c. THIS PAGE</b> Unclassified			<b>19b. TELEPHONE NUMBER (Include area code)</b>	

Standard Form 298 (Rev. 8/98)  
Prescribed by ANSI Std. Z39.18