NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Methods to Model and Calculate Capacity Contributions of Variable Generation for Resource Adequacy Planning

March 2011

to ensure the reliability of the bulk power system

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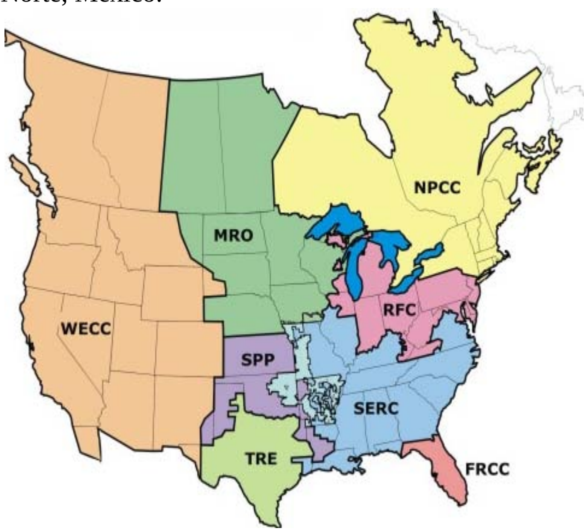
NERC's Mission

The North American Electric Reliability Corporation (NERC) is an international regulatory authority for reliability of the bulk power system (BPS) in North America. NERC develops and enforces Reliability Standards; assesses adequacy annually via a 10-year forecast and winter and summer forecasts; monitors the BPS; and educates, trains, and certifies industry personnel. NERC is the electric reliability organization in North America, subject to oversight by the U.S. Federal Energy Regulatory Commission (FERC) and governmental authorities in Canada.[1]

NERC assesses and reports[2] on the reliability and adequacy of the North American BPS divided into the eight Regional Areas as shown on the map below (See Table A).[3] The users, owners, and operators of the BPS within these areas account for virtually all the electricity supplied in the U.S., Canada, and a portion of Baja California Norte, México.



Note: The highlighted area between SPP and SERC denotes overlapping Regional boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.

Table A: NERC Regional Entities

FRCC **Florida Reliability Coordinating Council**	**SERC** **SERC Reliability Corporation**
MRO **Midwest Reliability Organization**	**SPP** **Southwest Power Pool, Incorporated**
NPCC **Northeast Power Coordinating Council, Inc**	**TRE** **Texas Reliability Entity**
RFC **ReliabilityFirst Corporation**	**WECC** **Western Electricity Coordinating Council**

[1] As of June 18, 2007, the U.S. Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce Reliability Standards with all U.S. users, owners, and operators of the BPS, and made compliance with those standards mandatory and enforceable. In Canada, NERC presently has memorandums of understanding in place with provincial authorities in Ontario, New Brunswick, Nova Scotia, Québec and Saskatchewan, and with the Canadian National Energy Board. NERC standards are mandatory and enforceable in Ontario and New Brunswick as a matter of provincial law. NERC has an agreement with Manitoba Hydro, making reliability standards mandatory for that entity, and Manitoba has recently adopted legislation setting out a framework for standards to become mandatory for users, owners, and operators in the province. In addition, NERC has been designated as the "electric reliability organization" under Alberta's Transportation Regulation, and certain reliability standards have been approved in that jurisdiction; others are pending. NERC and NPCC have been recognized as standards setting bodies by the Régie de l'énergie of Québec, and Québec has the framework in place for reliability standards to become mandatory. Nova Scotia and British Columbia also have a framework in place for reliability standards to become mandatory and enforceable. NERC is working with the other governmental authorities in Canada to achieve equivalent recognition.

[2] Readers may refer to the *Reliability Concepts Used in this Report* Section for more information on NERC's reporting definitions and methods.

[3] Note ERCOT and SPP are tasked with performing reliability self-assessments as they are Regional planning and operating organizations. SPP-RE (SPP – Regional Entity) and TRE (Texas Regional Entity) are functional entities to whom NERC delegates certain compliance monitoring and enforcement authorities.

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Executive Summary

The Integration of Variable Generation Task Force (IVGTF) was created December 2007 to develop a report and provide an analysis of technical considerations, specific actions, practices and requirements, including enhancements to existing or development of new reliability standards, for integrating large amounts of variable resources into the bulk power system. The NERC Special Report: Accommodating High Levels of Variable Generation[4] directed the Reliability Assessment Subcommittee to investigate consistent and accurate methods to calculate capacity values attributable to variable generation for the following methods:

This report presents:

1) Technical considerations for integrating variable resources into the bulk power system

2) Specific actions, practices and requirements, including enhancements to existing or development of new reliability standards

   - Calculations and metrics, including definitions and their applications used to determine capacity contribution and reserve adequacy.
   - Contribution of variable generation to system capacity for high-risk hours, estimating resource contribution using historical data.
   - Probabilistic planning techniques and approaches needed to support study of bulk system designs to accommodate large amounts of variable generation.

Systems planners require consistent and accurate methods to calculate capacity contribution attributable to variable generation to ensure the stability of the bulk power grid. Long-term historical data sets allow for characterization and trending of key performance metrics, including those factors that contribute to resource availability and adequacy. Variable generation, like wind and solar, does not have long-term historical data sets, and this lack of data limits the understanding of the long-term implications of variable generation performance. The potential output levels of variable generation show a large degree of variance over a vast geographic scale, so the ideal type and capacity contribution of variable generation will differ by region. This report discusses the known characteristics of regional variable generation along with the current practices used by systems planners to predict variable generation output potential and capacity contribution during peak-demand hours to ensure grid reliability.

[4] http://www.nerc.com/files/IVGTF_Report_041609.pdf

Key observations include:

Comparison of reliability-based approaches used to calculate the effective load-carrying capability (ELCC) of variable generation is needed.

The traditional approach is based on the Loss of Load Expectancy (LOLE) of 0.1 days/year as the reliability target. This approach considers only the peak hour of the days that have significant Loss of Load Probability (LOLP). This is typically a relatively small number of days because most of the year there is a surplus of capacity. A significant daily LOLE means that during the day there is some probability of insufficient generation, but the metric does not indicate the duration of the potential insufficiency, nor does it indicate the potential energy shortfall.

A Loss of Load Hours (LOLH) metric considers all hours during which there may be a risk of insufficient generation. With high penetrations of variable generation, this may be an advantageous metric because of the variability of these resources. This provides a more accurate assessment of adequacy in the sense that all hours are examined by the metric. However, unlike the daily LOLE, there is no generally-accepted hourly target. Additional analysis is required to determine the relationship between LOLE and LOLH reliability targets.

Alternative LOLP, LOLE, or related approaches for determining variable generation capacity contributions towards availability and adequacy should be considered.

Power system planners have adopted other metrics for resource adequacy. One common one is the Planning Reserve Margin. Unless the Planning Reserve Margin is derived from an LOLP study, there is no way to know what level of system risk is present. This is because some generators have higher forced outage rates than others. Therefore, one system with a 15 percent Planning Reserve Margin may not be as reliable as another system even though it also has a 15 percent Planning Reserve Margin.

There are existing simplified approaches to calculate wind capacity value. These can be easily extended to cover other forms of variable generation. In general, these methods calculate the resource's capacity factor over a time period that corresponds to system peaks. These approaches can provide a reasonably good, simple approximation to capacity value. However, system characteristics in some cases may result in a mismatch between a rigorously calculated ELCC and a peak-period capacity factor as an approximation to capacity value.

There appears to be variations in the way that imports, exports, and emergency measures are handled in reliability calculations.

Some of this is to be expected, based on differing approaches and rules in different power pools, and the differing nature of the capacity and energy delivery options between regions. In addition, different assumptions regarding interconnected resources would be expected to vary, based on the problem that is under evaluation. However, a suite of consistent and common approaches would be desirable and aid in comparisons among systems.

It will be critical to provide ongoing evaluation of the potential impacts of new variable generation resource on the grid.

Variable generation is anticipated to increase substantially in the North American grid. Because prospective variable generation plants, by definition, do not already exist, obtaining data that can describe the likely behavior of future plants is critical for a number of reliability, adequacy, and integration tasks that are performed in the planning cycle. Because weather is the principle driver for load and for variable generation output, it is critical to maintain chronology between variable generation and load. Specific locations of future variable generation may not be known with certainty, and to evaluate the likely impacts multiple scenarios may need to be evaluated. Because of these issues, it will be critical to develop and maintain a public database of wind and solar estimated (future) production. Large-scale NWP models or solar radiation and cloud cover models can be used to provide high resolution wind power and solar power data. The value of this type of dataset has been shown in the Eastern Wind Integration and Transmission Study (EWITS) and the Western Wind and Solar Integration Study (WWSIS).

Industry education on metrics and calculation used for capacity contributions will provide a better outlook on the true nature of variable generation.

Based on the experience of many participants of the IVGTF Task Force 1.2, it seems apparent that the workings of LOLP, ELCC, and related reliability approaches are not always well-understood. This highlights the need for the dissemination of information regarding the behavior and performance of these metrics.

Performance tracking of variable generation is needed for the understanding of various technologies' resource adequacy contributions.

Calculating capacity value for existing variable generation sources requires chronological generation data that is synchronized with load data and other relevant system properties. Existing power system data bases can be used to track this data, which would be useful in helping to better understand variable generation performance and operational issues (addressed by other work streams of the IVGTF). NERC already collects data to inform the GADS database. Although it is more data intensive than the GADS process, operational data from variable generation over the next several years will be extremely valuable in the assessment of capacity value and operational issues surrounding the use of variable generation.

Summary of Recommendations

This report provides the reader with a general framework for determining the contributions and best use of variable generation to bulk power grid. In order to ensure the proper allocation of the increase in variable generation, NERC suggests[5]:

Metric	• Additional research to equate traditional reliability targets (such as a LOLE of 0.1day/year) to alternative metrics. • LOLP, LOLE, or other related metrics should be used to calculate generation adequacy and capacity contributions of VG • We envision more widely-adopted energy-related reliability metrics and targets as the share of variable generation increases in the power system and recommend comparisons of results based on these alternative metrics. • Planning reserve margin, calculated as a percentage of system peak, will become less meaningful with large penetrations of variable generation, and perhaps defunct in the future.
Multi-area Reliability Adequacy	• Alternative approaches and assumptions regarding the treatment of interconnected systems should be transparent to the analysis. • Development of one or more common approaches for handling the impact of interconnected systems in the reliability assessments will be useful.
Alternative Approaches	• Planning reserve margin levels should be periodically benchmarked with, or derived from, an LOLP or related approach to resource adequacy to ensure the account for any changes. • Simplified approaches should be benchmarked and calibrated to the rigorous ELCC calculations to ensure the validity of the approximation.
Data Collection	• NERC should design and implement a way to collect high-quality variable generation data that would help inform calculations of capacity value. • NERC should request that government agencies like the DOE, working with NOAA/NCAR, develop annual high-resolution, modeled wind and solar power data on 10-minute time scales and 2 km geographic grids.
Education	• NERC should facilitate the dissemination of information about how LOLP-related reliability and adequacy calculations perform and what they measure.

[5] See page section 6 for a more in-depth description of NERC suggestions based on this report.

1. Introduction

1.1 Background

The North American Electric Reliability Corporation (NERC) is responsible for ensuring the reliability of the bulk power system in North America. Anticipating the growth of variable generation, in December 2007, the NERC Planning and Operating Committees (PC and OC) created the Integration of Variable Generation Task Force (IVGTF), charging it with preparing a report to identify the following:

1) Technical considerations for integrating variable resources into the bulk power system
2) Specific actions, practices and requirements, including enhancements to existing or development of new reliability standards

One of the identified tasks from the final report[6] from this task force was the need for the models for variable generation technologies. For the purpose of completeness of this document, the proposed action item Task 1-2 is repeated below:

1.2. Consistent and accurate methods are needed to calculate capacity credit (sometimes called capacity value) attributable to variable generation.

Investigate consistent approaches for calculating resource energy and capacity associated with variable generation for the following methods:

- Effective Load Carrying Capability (ELCC) approach
- Contribution of variable generation to system capacity for high-risk hours, estimating resource contribution using historical data
- Probabilistic planning techniques and approaches needed to support study of bulk power system designs to accommodate large amounts of variable generation

1.2 Objective and Overview

The goal of bulk power system planning is to ensure that sufficient energy resources and delivery capacity exists to meet demand requirements in a reliable and economic manner. System planners use forecasts of future demand along with existing and planned resources to determine, on a probabilistic basis, if those resources will be sufficient to meet reliability targets. In addition to ensuring sufficient resources and capacity to meet demand under normal operating conditions, planners must also ensure adequate reserves exist to reliably serve demand under credible contingencies, such as the loss of a single generating unit or transmission line.[7] This report describes how NERC regions should model variable generation for resource adequacy assessments in the planning timeframe. Variable generation contributes towards both capacity

[6] http://www.nerc.com/files/IVGTF_Report_041609.pdf
[7] NERC, *Reliability Concepts, Version 1.0.2*, Dec 2007.

and energy adequacy. Because most regions are capacity-constrained, the focus of the discussions is on contributions to capacity adequacy. The goal is to define a compendium of "best practices" for evaluating variable generation's contribution to resource adequacy.

Traditionally, bulk system planning included generation planning and transmission planning. Generation planning is now referred to as resource adequacy planning, acknowledging the increased role of demand-side resources. Resource planning and transmission planning are inter-related as delivering resources to demand centers may require additional transmission. Planning a reliable bulk power system with high penetrations of variable generation may require an iterative approach between generating resource and transmission planning. The transmission system increases the availability of remote generation (and loads) that alters the character of the resource mix. Therefore, transmission ties to these remote resources are disabled in some studies. A larger area changes the diversity of loads and variable generation, increasing reliability measured with a lower Loss-of-Load-Probability (LOLP). This issue is discussed in a later section of this report.

This analysis may also change the capacity credit on variable generation by disassociating the geographic location of the variable generation with the geographic location of the peak load within a wider region. The power transfer capacity of transmission associated with the Energy Markets integrated with wind generation may change the planning reserve levels at peak conditions. Therefore, it is important to define the relevant footprint and characteristics that should be subject to modeling.

The increasing penetration of variable generation resources makes it important to define "best practices" for quantifying the contribution of these resources to resource adequacy. The most common resource adequacy metrics are Loss-of-Load-Expectation (LOLE) and its more commonly used derivative metric; the Planning Reserve Margin. Because many variable generation sources have relatively low capacity credit relative to installed capacity, the relevance of the Planning Reserve Margin metric will be limited or non-existent in systems with high penetrations of variable generation.

The analytical processes used by planners evaluates whether sufficient resources are available to meet future system requirements range from relatively simple calculations of Planning Reserve Margins to very rigorous production cost-based reliability simulations that calculate system LOLE or LOLP values. It is common to identify some percentage reserve margin of capacity over and above load requirements to demonstrate that a geographic region meets state regulatory and regional reliability requirements. The reserve margins either expressed in megawatts (MW) or as a percentage of peak load, are determined by calculating the capacity of supply resources and compared to the expected peak loads. For some resources whose output is variable such as run-of-river hydro, wind and solar, the capacity is discounted to reflect the probability of the availability of the resources at high risk (high LOLP) times. Most planners then periodically confirm the adequacy indicated by the calculated reserve margins through detailed reliability simulations that compare expected load profiles with specific generating unit forced outage rates and maintenance schedules to yield LOLE, LOLP or expected unserved energy (EUE) values.

The planner must demonstrate that a resource adequacy criterion is met using this more detailed simulation. An equivalent Planning Reserve Margin, generally expressed as a percentage normalized against peak demand, is a simplifying representation of resource adequacy that is suitable in the appropriate context. It is appropriate to undertake more detailed resource adequacy assessments to evaluate options and make decisions related to power system planning.
This report focuses on energy sources that are variable and have limited, if any, dispatchability, comprised of generation from wind, solar photo-voltaic (PV), and concentrating solar power (CSP) resources (CSP may be installed with thermal storage, which would mitigate variability and uncertainty compared to CSP without storage). Wave energy may also fit this definition, but proponents believe it is more predictable than other types of variable generation and so might be included in the energy-limited category of resources. While generation from run-of–river hydro resources, and to a lesser extent hydro systems with reservoir capability, is variable and can affect its contribution to meeting peak loads, its output can typically be better anticipated for days and weeks in advance thus allowing for an orderly deployment of other dispatchable resources. Variable generation's attributes will vary by geographic area and climatic regime, so it is entirely possible to have wind, for example, contributing 60 percent of its installed capacity toward capacity adequacy in one area and none in another area. It is necessary to have a sufficient data record to be able to evaluate, with confidence, the statistical attributes of variable generation and identify any statistical relationships with other important parameters, such as load levels (i.e. via temperature), in order to quantify contribution to capacity.

The traditional definition of resource adequacy includes two parts: development of a reliability target and application of a method to determine whether a given system meets the target. In some cases, balancing areas (or other entities) do not explicitly develop a reliability target, but instead adopt a peak Planning Reserve Margin (as a percent, capacity reduced by projected peak and normalized by project peak). This peak Planning Reserve Margin is not the same as an operating reserve margin, because it focuses on the required level of capacity that is necessary compared to a projected peak load level. Operationally, some generators may be unavailable in any given hour or day because of mechanical or electrical failure or because they are not in service. Further demand, may be higher than the 50/50 forecast. In this case, there still must be sufficient *operating* reserve available to maintain reliability in an operating time frame. For this reason, industry experience has shown a Planning Reserve Margin in the range of 10-18 percent over 50/50 forecast peak load will result in sufficient operating reserves.

The traditional reliability-based planning approaches adopt a reliability target, which may result in higher or lower Planning Reserve Margins depending on the forecast and forced outage rates of generating units. For example, if two systems are otherwise identical, but with different forced outage rates for most of their respective generation fleets, system A may require a 12 percent Planning Reserve Margin to attain its LOLE reliability target of 0.1days/year, whereas system B may require a 15 percent Planning Reserve Margin to attain the same LOLE target. Should there be a large penetration of variable resources, whose contribution to the peak load is less certain; the Planning Reserve Margin may increase because the capacity value of variable generation is typically a relatively small percentage of its *installed* capacity, depending on the level of variable generation penetration. The expected Planning Reserve Margin is not useful without providing a corresponding target Planning Reserve Margin value and LOLE target. By itself the expected Planning Reserve Margin cannot communicate how reliable a system is and whether it has sufficient resources to reliably meet customer loads. In order to retain meaning associated with this widely used reliability measure, this report addresses techniques for modeling the estimated "typical" resources to simulate the contribution that variable resources have to reserve margins. These estimate resources can be seen as capacity additions of convention generation, which are replaced by variable generation. A metric such as expected unserved energy (EUE) may be more appropriate than loss-of-load metrics with high levels of variable generation that are often energy-limited resources.

Variable generation that is connected to distribution system (i.e., distributed generation-DG), may be modeled as a decrease in wholesale demand for electricity or by considering it as a resource. Different methods to model and calculate the impact of this variable generation may be employed depending on whether or not the distributed variable generation is modeled on the resource side or as a reduction to demand. Should significant distributed variable generation appear to be more likely, capacity valuation and the associated resource adequacy implications of variable generation should be considered insofar, as those issues affect the bulk power system.

2. Traditional Resource Adequacy Planning

2.1 LOLE & LOLP

A Loss of Load Expectation (LOLE) or Loss of Load Probability (LOLP), analysis is typically performed on a system to determine the amount of capacity that needs to be installed to meet the desired reliability target, commonly expressed as an expected value, or LOLE of 0.1 days/year. This calculation involves combining the load profiles and the scheduled generator outages with the probability of generator forced outages to determine the expected number of days in the year when a shortage might occur. Because the result is actually an expected value over a specific time period, the index is a Loss of Load Expectation, or LOLE, but the historical terminology is LOLP based on the calculation technique employed. Both terms are often used interchangeably, often to describe LOLE.[8] The historical measure was interested in "the number of days of shortage" rather than the total outage time. Since generator outages tended to last for several days, the outage was assumed to be coincident with the daily peak load. Therefore, the calculations were completed for the peak hour of each day. For the discussion that follows, we use "LOLP" whenever we refer to a probability. We use "LOLE" when describing a metric that is an expected value, such as 0.1 days/year, and to describe various analyses based on LOLE, when appropriate.

LOLE analysis also forms the basis of calculating how much a particular generator, or group of generators contribute towards planning reserve, given a reliability target (the desired target is 0.1 days/year is assumed for the discussion that follows, although any suitable target can be used as appropriate). The calculation of this capacity contribution is called effective load carrying capability (ELCC) and is conceptually related to the 'operable capacity' metric being developed by the Resources Issues Subcommittee.[9] Although it is common to base the ELCC on LOLE, other suitable reliability metrics such as expected unserved energy (EUE) can be used in lieu of LOLE. The ELCC can be calculated relative to several possible benchmark units or loads. For example, one might calculate the ELCC in terms of an increase in load that can be supplied at the target reliability level; in terms of a perfect generating unit; or in terms of a given unit type with a specified forced outage rate.

The fundamental calculations of LOLP, LOLE, and ELCC are not new, nor are they unique to variable generation. The reliability-based approach to calculating resource adequacy is a robust method that allows for the explicit estimate of the shortfall of generation to cover load. The traditional use of LOLE is to determine the required *installed* capacity, based on expected capacity during peak periods, and ELCC measures an individual generator's contribution to overall resource adequacy.[10]

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[8] LOLP is elaborated in the Appendix A8

[9] The proposed 'operable capacity' concept being developed by the RIS envisions using the resource rating less an amount determined by a derating factor such as EFOR, EFORd or other empirically derived performance factor.

[10] An IEEE Task Force on Wind Capacity Value has completed a report, *Capacity Value of Wind Power*, in press, IEEE Transactions on Power Systems.

LOLE calculations can be done hourly or daily. The general principle is to start with a full year (or more) of data and calculate LOLE for each time period. During off-peak periods and times when there is excess generating capacity available, LOLE values will usually be zero. Non-zero LOLE values occur during peak periods and near-peak periods, and possibly during times that large amounts of capacity are undergoing scheduled maintenance and is therefore unable to provide capacity. The LOLE calculation effectively looks for hours or days when there is some risk of not meeting load, discarding the vast majority of days or hours during which there is little to no risk (LOLE≈= 0).

ELCC essentially decomposes the contribution that an individual generator (or group of generators makes to overall resource adequacy. A generator contributes to resource adequacy if it *reduces the LOLE* in some or all hours or days. Conventional generators' contribution to adequacy is typically a function of the unit's capacity and forced outage rate. For variable generation, the contribution to adequacy is a function of the time of delivery and the LOLE reductions that would be achieved with that resource. Because there is no LOLE during most hours or days of the year, a resource can only contribute to resource adequacy if it generates during times of non-zero LOLE. For example:

- Summer peak with solar generation that is perfectly correlated with peak loads would receive a significant LOLE reduction from the solar plant. In this case the solar plant would have an ELCC that is close to its rated capacity
- Summer peak with solar generation that is somewhat correlated with peak loads, but clouds and/or ozone haze reduces the solar output during peaks. The solar plant would have a lower ELCC than if it were perfectly correlated.
- Summer peak with wind generation whose output is well-correlated with peak loads, providing significant wind energy during peak periods. The wind generation would have a moderate ELCC (perhaps 30-40 percent, which would be high for wind) of rated capacity.
- Summer peak with wind generation that is poorly correlated with peak loads. During summer peak periods, the wind provides approximately 10 percent of its rated output. This wind plant would receive a low ELCC in the neighborhood of 10 percent of its rated capacity.
- Summer peak with wind generation that is poorly correlated with its own peak loads but which is interconnected to a large electric transmission system where the peak loads occur at different times. During summer peak periods, the wind provides approximately 18 percent of its rated output toward the wider inter-regional peak load. This wind plant could receive an improved ELCC in the neighborhood of 18 percent of its rated capacity.
- Winter peak with wind generation that is unable to provide energy during peak periods. This wind plant would receive a capacity value that is close to, or equal to zero.

The above examples assume that peak load and LOLE are perfectly correlated. Although this correlation is typically high in practice, it is not always perfect, and in some cases may be less than one might expect. For example, an analysis in California[11] found high LOLE values that occurred in late fall, caused by unusually hot weather and a reduction in the hydro run-off that coincided with planned maintenance schedules for a significant amount of generation capacity.

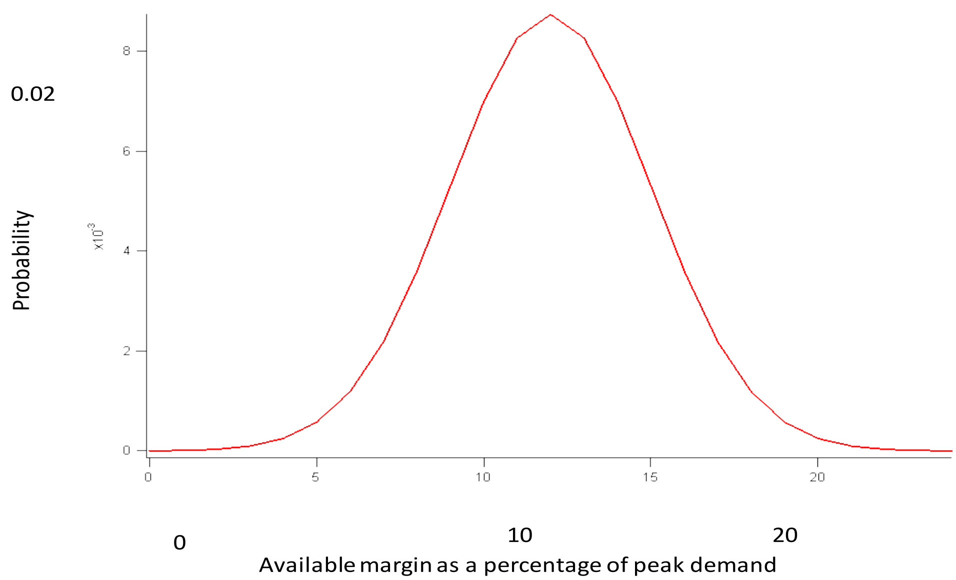
[11] D. Hawkins, B. Kirby, Y. Makarov, M. Milligan, K. Jackson, H. Shiu (2004) RPS Integration Costs Phase I Analysis Results Workshop • 20 February 2004, California Energy Commission. Sacramento, CA.

During this period of time, the risk of loss of load was higher than would normally be expected. The LOLE analysis finds days or hours that have unexpectedly high risk profiles.

LOLE analysis is used to determine the level of installed generation that is needed to achieve a given level of resource adequacy. Traditionally, this level of adequacy has been 0.1day/year, but different regions or different entities can choose the appropriate target. In this discussion we use the traditional target, but emphasize that other targets may be appropriate.

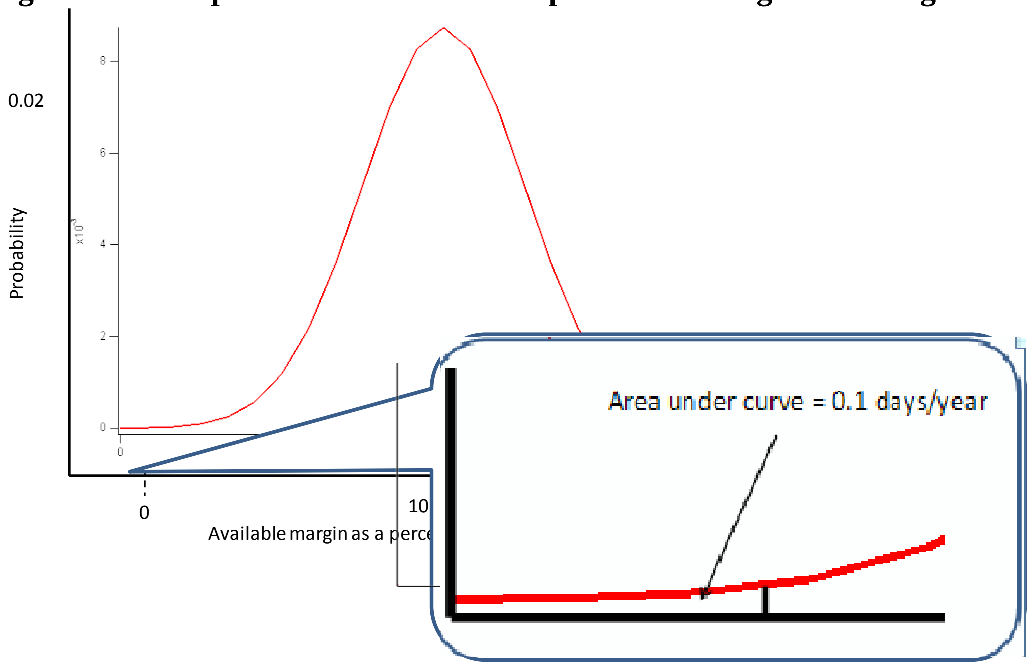
Figure 1 illustrates the concept of LOLP, which is used in the calculation of LOLE. For most of the year, there is sufficient reserve margin, but during some days (or hours) there is a non-zero probability that multiple generation failures may result in insufficient reserves and possibly load shedding. The left tail of the probability distribution shows the probability levels associated with zero or negative reserves is low, but non-zero. We emphasize that the graphical depiction of this distribution has been altered so that the tail is easily visible to help motivate the discussion. The area under the left tail and to the left of the 0 percent reserve point is the cumulative loss of load expectation – the summation of all probabilities in the left tail.
Figure **2** enhances this tail to make it more easily visible.

Figure 1: Example LOLP curve



These curves can be used to describe how the ELCC calculation is carried out. Starting with a system that achieves the desired reliability target of 0.1days/year, a new generator is added to the resource mix. The area under the left tail decreases, which in turn increases the reliability level. Additional load is then added to the system until the reliability target is met. The additional load that can be supplied at the original reliability target is the effective load carrying capability of the generator in question. Depending on the type of resource added to the system, the shape of the LOLP curve may change, but using this algorithm (or one of many related approaches) results in a system with a new resource that achieves the same reliability target as before. Thus, the area in the left tail of the probability distribution is the same with the new generator and the higher load level, as compared to the system without the new generator at the original, lower load level. This technique could be applied to all types of resources and not just variable generation to determine the reliability contribution of any individual resource.

Figure 2: Example LOLP curve with emphasized tail region showing LOLE



A simple example is shown graphically in Figure 3 (the units of the emphasized portion of the graph have been eliminated but are the same as the main figure). In the example system, the annual peak load is 10 GW, and this load can be supplied at the target of 0.1days/year. The original reliability curve is upward-sloping with respect to the load meaning that as load increases, the LOLE reliability index increases or conversely, reliability declines as load increases. The curve shows this relationship, holding the generator fleet and characteristics constant. In this system, as in all other real systems, the risk of not meeting load occurs primarily during the near-peak days and hours, although the precise timing of these non-zero probabilities of load loss depends also on factors such as scheduled maintenance, transaction schedules, and hydro dispatch, among others. In the example system in the diagram, there are multiple days that make a contribution to the 0.1 days/year LOLE, although they are not shown explicitly on the graph.

When a new generator is added to the resource mix the original reliability curve shifts to the right. Each load level can now be supplied at a higher level of reliability than before. The new position of the reliability curve (after shifting to the right) indicates that additional load can now be supplied while maintaining the 0.1days/year reliability level. Figure 3 shows that as a new resource is added, the LOLE index is reduced (red arrow). This allows for an increase in loads as shown by the blue arrows. For example, the additional 150 MW that can be supplied at the target reliability level may come from the addition of a 165 MW thermal unit with a forced outage rate of approximately 0.09. In this case, the new unit has an ELCC of 150 MW, which indicates that the unit contributes 150 MW towards planning reserve. Because almost any generator will move the reliability curve to the right, even slightly, the position of the final curve indicates the combined contribution of all units towards resource adequacy, whereas the ELCC of a particular unit shows how that unit contributes to resource adequacy.

There are several computational techniques that can be used to calculate the LOLP, EUE, or other reliability metrics, but those are generally well-documented and are beyond the scope of this report.

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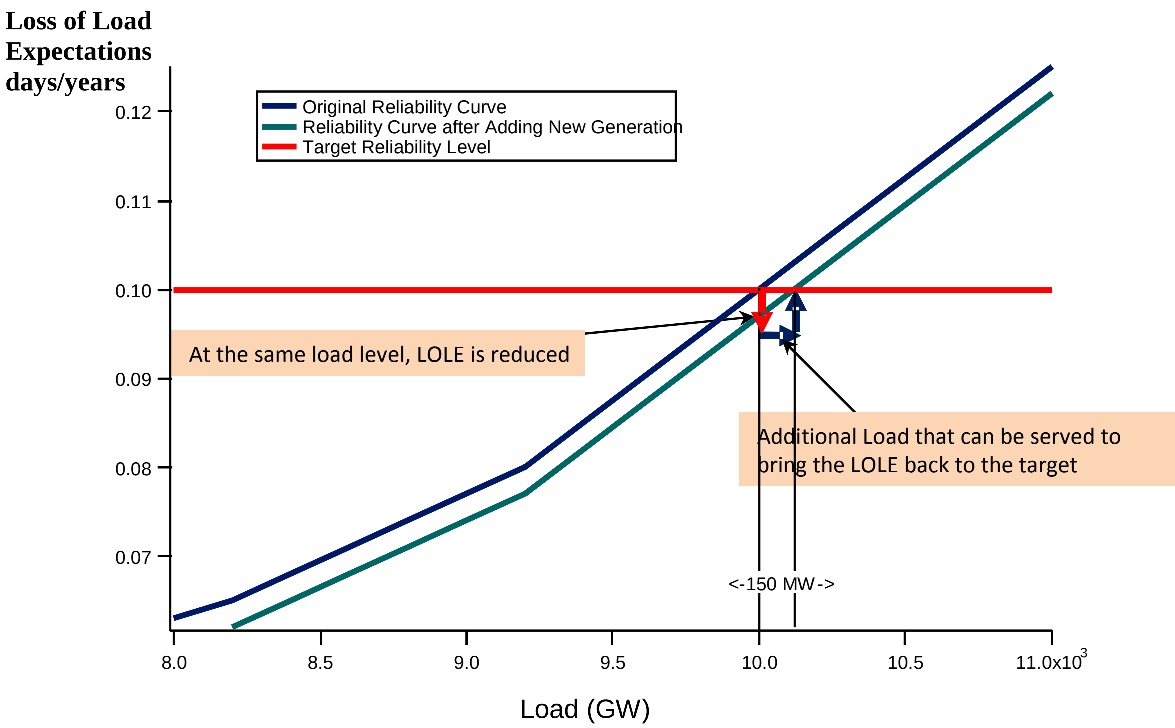
Figure 3: Example of reliability curves when a new generator is added to the resource mix



2.2 Traditional Reliability Targets

The traditional reliability target used for resource adequacy is 0.1days/year. This metric can be traced back to at least 1947 in a paper presented by Giuseppe Calabrese at the IAEE Midwest Generation Meeting in Chicago, although the precise origin of the 0.1days/year target is not known with certainty. In the ensuing years, this 0.1days/year target has been retained as the acceptable level of risk, although there have been many refinements in the calculation of this metric.

To calculate reliability level expressed in days/year requires daily load peaks, generator capacities, and forced outage rates. The basic approach involves transforming the generator data into a capacity outage probability table[12] and from that information the LOLE can be determined by calculating the sum of the daily LOLP values.[13] The LOLE is the area discussed above in Figure. For variable generation, a chronological profile (hourly or daily) of the generation level, synchronized with the load, is also required. We discuss this further below.
This days/year metric is not the same as, and cannot be easily converted, into an hours/year metric. The traditional approach effectively counts the number of days that could experience a capacity shortage, and is not concerned with the number of hours of the outage. A loss of load hours (LOLH) metric, by contrast, is concerned only with the number of hours of shortfall, and does not include any dimension for persistence of an outage event and therefore there is no quantification about how many days the outage is spread over.

To apply the traditional approach to variable generation, time synchronized data from the variable generation with loads are required because they both depend on the underlying weather driver. For example, a summer peaking utility with a large PV plant would likely experience high loads during sunny periods that induce more air conditioning usage, and at a time that relatively high photovoltaic output would be available. Using synchronized data ensures the underlying correlation of the weather. Conversely, if different years' of data are used for the solar and load, the load may be high (from a sunny hot day) while the solar data is from a cloudy day.[14] Similar concerns arise for wind and load data that are not time synchronized.

Because solar and wind data can change the profile of the load that must be served from the non-variable generation fleet, the effective daily peak may occur at a different time of day than would be the case with no variable generation. To apply the traditional days/year reliability metric, this should be taken into account (See Appendix A and the discussion of the Western Wind and Solar Integration Study (WWSIS) results).

With higher levels of variable generation on the power system in the foreseeable future, it may be desirable to modify the usual reliability target of 0.1days/year and move to a suitable hourly target and analysis. This may provide a more robust and detailed measure of loss-of-load risk than a daily metric. For relatively low penetrations of variable generation, this may not be a significant issue. However, as variable generation penetration grows, a probabilistic model that does not consider chronology and utilized time-synchronized load and variable generation data

[12] Billinton and Allen, "Reliability of Power Systems." 2nd edition, Plenum Press.
[13] The terms LOLP and LOLE are often used interchangeably in power system reliability analysis
[14] J. Charles Smith et al, "*Utility Wind Integration and Operating Impact State of the Art*" http://www.nrel.gov/docs/fy07osti/41329.pdf

may be limited in its ability to capture the relevant risk, and therefore may not correctly measure system LOLP. It may be possible for an external analysis to be performed and input into the probabilistic load model, or perhaps a different type of model will be needed at high penetration levels.

When variable generation is added to the generation mix, it is possible (or even likely) that the timing and magnitude of the net peak—the peak that must be met by the conventional non-variable generation fleet—may change. For this reason, selecting a single daily peak hour without considering the impact of variable generation will generally not provide an accurate measure of the risk of not meeting load. For this reason, an expanded LOLP or LOLE metric that takes the net-load peak into account is needed. This is the approach used in the Western Wind and Solar Integration Study, discussed in Appendix A.[15]

Until recently, new generators have generally added significant energy capability along with the capacity they provide. With the advent of newer energy limited technologies replacing older ones (e.g. with emerging larger penetrations of variable generation), an assumption of energy adequacy cannot be made simply on the basis of capacity adequacy. Future-looking detailed probabilistic assessments of resource adequacy (energy, capacity and operability), transmission adequacy and congestion are increasingly becoming an essential requirement, consistent with the growing penetration of variable generation, and in the changing non-renewable supply mix environment. Energy modeling capability can be beneficial for conducting complex power system planning analysis, where the interplay between demand, resources and transmission over many weeks and months needs to be well understood. Energy modeling programs allow for detailed probabilistic assessments of resource adequacy, transmission adequacy and congestion and, to varying degrees, system operability over timeframes of typically one year or more, with hourly resolution.

This leads to other related reliability metrics that can be used. One common metric is expected unserved energy (EUE). LOLE metrics only consider the number of days or hours during which a shortage might occur, and do not take into account of the depth of the shortfall. Conversely, EUE measures the energy shortfall, yet does not provide information concerning the number of hours or days of shortfall. A metric like EUE may be a valuable additional metric as power systems evolve to more variable generation resources. This is also consistent with emerging interest in energy-first planning, which is an approach that recognizes requirements in some states for a minimum level of generation from renewable (usually variable) generation. The approach begins by developing the renewable resource mix, and then proceeding to determine the efficient mix of generation for the balance of system build-out. The result of this type of generation expansion is that the generation characteristics needed to balance variable generation is consistent and provides the required level of flexibility. A resource adequacy metric on its own cannot directly address system flexibility need; for this, another metric is needed. This issue is pursued in more detail in Task 1.4.[16]

[15] See section A3.1 for a discussion.
[16] Special Report, Flexibility Requirements and Metrics for Variable Generation: Implications for System Planning Studies, available at http://www.nerc.com/docs/pc/ivgtf/IVGTF_Task_1_4_Final.pdf

As the level of variable generation continues to grow as a share of overall energy production in the electric power system, analyses that calculate and compare these metrics, and perhaps other related metrics, are desired. To promote a better understanding of the impact of variable generation on both capacity adequacy and energy adequacy, we recommend additional research and analysis in this area.

Example results from the WWSIS in the appendix illustrate the application of some of these metrics to wind and solar generation.

2.3 Inter-Annual Variability

The primary contributors to the ELCC of thermal power stations are the capacity and mechanically based forced outage rate of the unit in question. Typical mechanically based forced outage rates are low for base-load and cycling units, and historically have been higher for combustion turbines. Figure 4 shows an example from the Western Interconnection. Most forced outage rates are below 10 percent, although there is considerable variation. These data are based on NERC's GADS database, which represents long-term performance from different types and sizes of generators.

An approximation to a thermal unit's ELCC can be calculated using the unforced capacity:

$U = (1 - F)\, C$

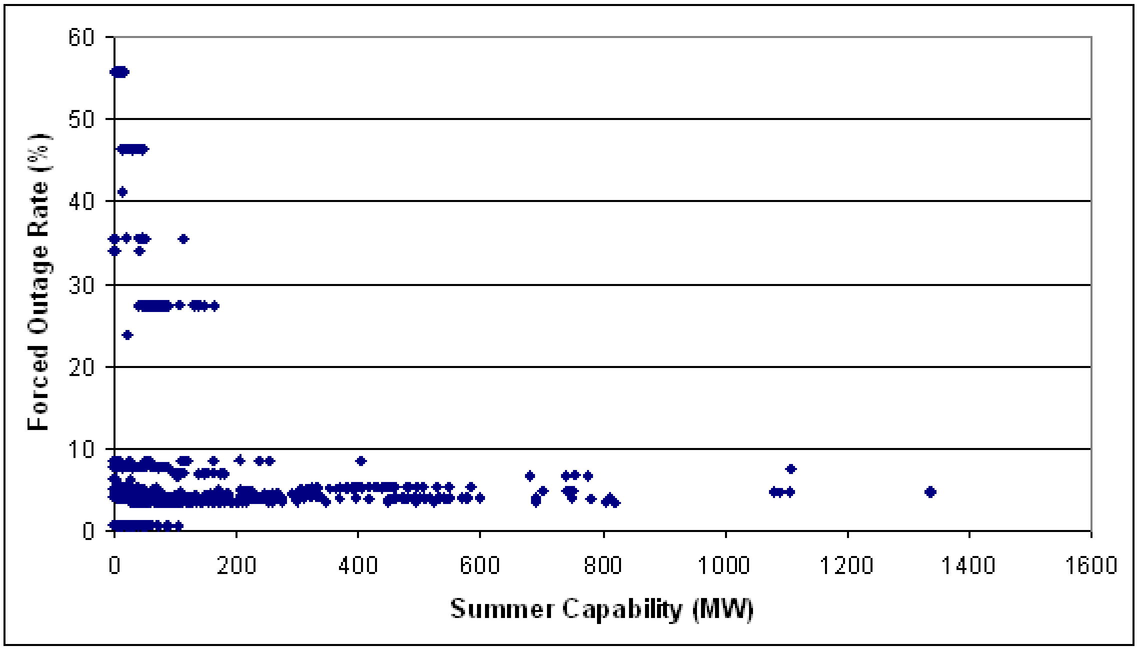
Where:

U = unforced capacity (MW)
F = forced outage rate
C = capacity (MW)

Most years one would expect that the unit would be available at its rated capacity. But it is possible that the unit could fail during critical periods, with probability *F*. If a 300 MW unit with a mechanically based FOR = 0.10 and unforced capacity of 270 MW (and, we assume for simplicity of the example this unit has 270 MW ELCC) were to fail during peak periods, sufficient planning reserve capacity would normally be available to make up the difference. We note, however, that even a reliable system with a 0.1days/year level of adequacy is not immune to shortage events. This (or other appropriate) target is typically chosen as a tradeoff between reliability and cost.

Inclusion of variable generation is somewhat more complex. The driver for the ELCC of a variable generation is not typically its mechanically based forced outage rate, but the coincidence of its delivery profile relative to high-risk/peak load periods. Energy sources like wind and solar vary in their delivery profile from year to year, so, like conventional generation, it is possible that a given year's delivery would be either higher or lower than the long-term ELCC value.

Figure 4. Example capacities and forced outage rates from the WECC



Several recent studies of wind ELCC have been performed, with some studies also including photovoltaic and concentrated solar plants with thermal storage. Two of these studies are summarized in the appendix to this report. Reviewing the inter-annual variability of ELCC for wind is useful, and we extract some of the appendix material for this discussion.

Figure 5 is taken from a recent study that analyzed the impact of up to 35 percent variable generation in the WestConnect footprint of the Western Interconnection.[17] The study used synchronized load shapes, wind, and solar data from 2004-2006. Using this 3-year period, it is apparent that there is some variation in the wind ELCC, both based on penetration and year. The variation does fall within a fairly narrow band producing an ELCC of 10-15 percent of rated capacity of the wind.

Figure 5. Inter-annual variation in wind ELCC from the Western Wind and Solar Integration Study

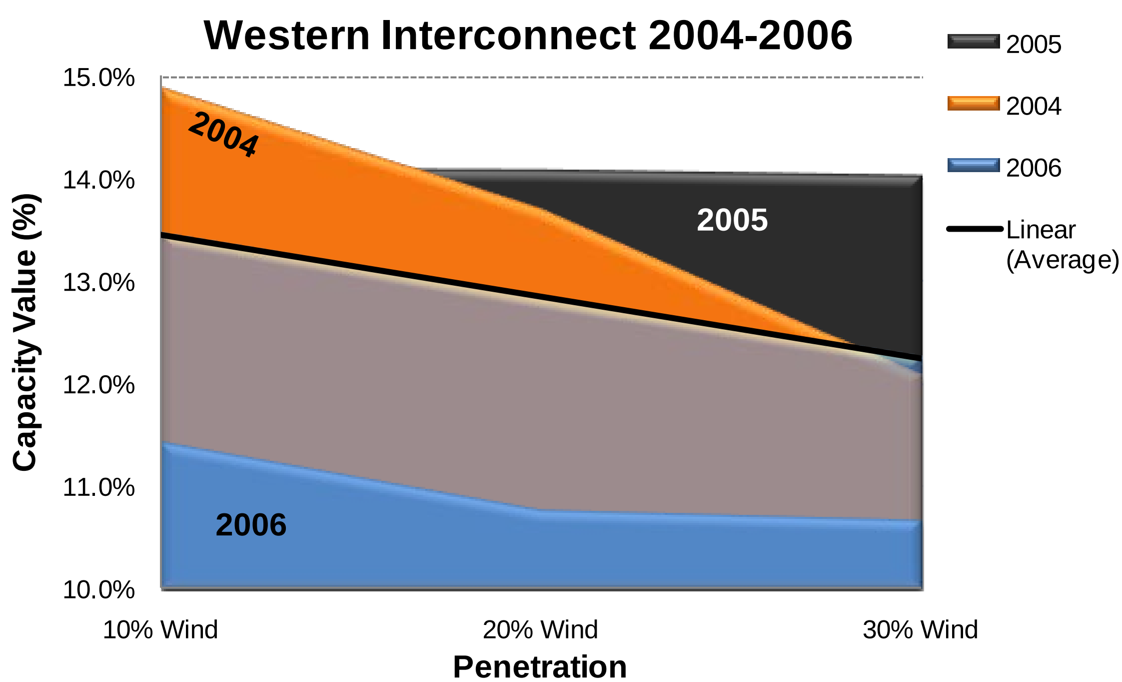


Figure 6 is from the Eastern Wind Integration and Transmission Study, covering most of the Eastern Interconnection (US). Using time synchronized wind and load from the same 3-year period as the Western study, 2004-2006 this study found somewhat more variation from year to year. The scenarios represent different geographical combinations of locations that result in the given energy penetration, which is 20 percent for the first 3 scenarios, and 30 percent for scenario 4.[18] Much of the differences between these two scenarios is likely attributed to the higher levels of off-shore wind capacity in scenarios 2-4, which typically has a higher capacity value than on-shore (based on what is known to date). Using this three-year period, it is apparent that there is some variation in the wind ELCC, both based on penetration and year. The variation does fall within a wider range than in the Western study producing an ELCC of 15-30 percent of rated capacity of the wind.

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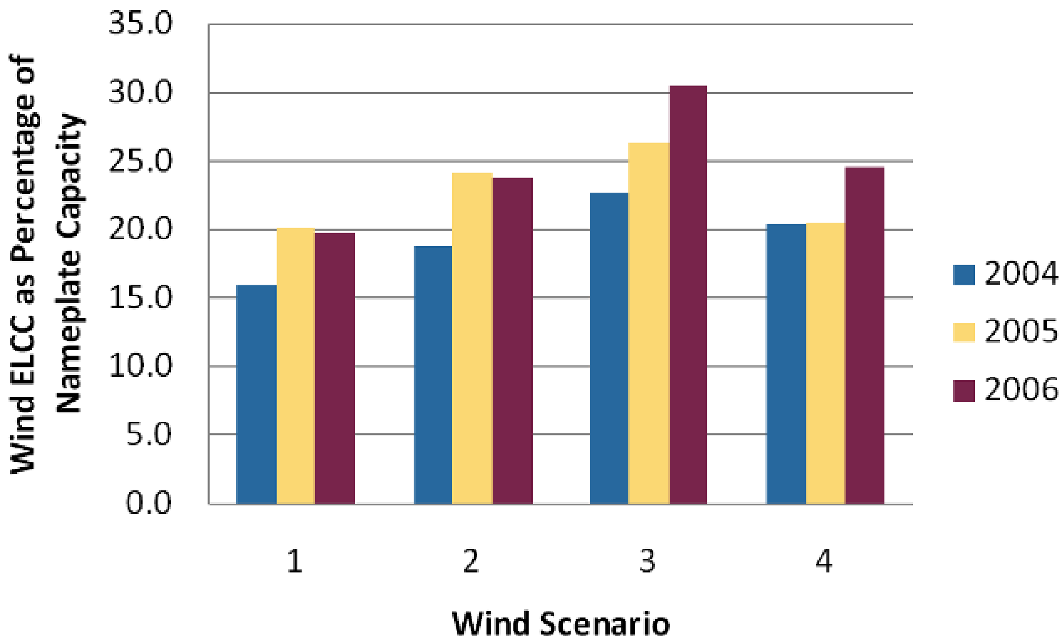
[17] Solar penetration of up to 5 percent is included in these scenarios, but not in the graph. All penetration rates are based on renewable energy as a percentage of annual energy demand.

[18] Scenarios: (1) 20% wind energy penetration, high capacity factor, onshore (2) 20% wind energy penetration, hybrid with offshore (3) 20% wind energy penetration, local wind with aggressive offshore (4) 30% wind energy penetration, aggressive onshore and offshore.

Figure 6. Wind ELCC from Eastern Wind Integration and Transmission Study (EWITS)



2.4 Factors that Influence the LOLP and ELCC Calculations

Although the primary drivers of LOLP and ELCC are load, unit capacity, available energy supply to the prime-mover and mechanically based forced outage rates, there are other factors that can influence the results. We begin with a short discussion of LOLP.

Because LOLP is a function of the generator characteristics and load, the size of the electrical footprint has a large influence over the calculation. When multiple balancing areas or regions are pooled for the calculation, load diversity and the assumption of random independent forced outage rates tends to reduce the LOLP. In fact, these are precisely the factors that have driven the formation of reserve-sharing pools over the past several decades. Absent significant transmission constraints, larger systems can achieve a higher level of reliability. Building new transmission can reduce LOLP, and can therefore reduce the need for new generation.

To assess a particular region or balancing area's reliability level, it is common to place restrictions on the energy that can flow on the ties to neighboring systems. In some cases, these may be set to zero; in other cases, these flows may be set to some value judged to be typical or that represents an appropriate conservative assumption. In either of these cases, the LOLP may not be measuring the probability of an actual loss of load event. Instead, it may be measuring the probability that imports may be necessary to provide sufficient generation.

When regions are linked together with new transmission, the impact on LOLP is similar: the new transmission makes remote generation available in an emergency, as well as for imports. Similarly, local generators may now access more remote energy markets. In addition, there is not always a consistent accounting among neighboring systems for emergency procedures to alleviate a generation-caused loss of load event. The result is that the LOLP, LOLH, and other related reliability metrics will change based on the assumption of the footprint and interconnection with neighboring systems, and with the underlying inputs to the model. As the size of the footprint increases, the correlation of the aggregate peak load becomes less correlated with the meteorology of a particular wind resource location.

Because ELCC is a function of LOLP, changing assumptions regarding transmission links to neighboring areas will also have an impact on the ELCC of generators, and may have a larger impact on variable generation than on traditional generation. This impact is illustrated in the Appendix A.

3. Data Requirements

Long-term historical data sets exist for thermal generation reliability that allows reasonably good characterization of key performance metrics, including those factors that contribute to resource availability and adequacy. Similarly, most hydro systems have long-term flow records so that inter-annual variability can be reasonably assessed.

With some exceptions, new forms of variable generation like wind and solar do not have sufficient long-term data to allow for the same level of characterization of generation patterns and output levels that are subject to the weather. Although there is a long-term weather record, that data does not adequately describe the atmosphere at levels where wind turbines are able to extract available energy, nor do they accurately characterize solar insulation at actual or potential solar generation sites.

Given the early development stage of variable generation, it is not yet clear how many years of data would be appropriate to estimate a reasonable long-term capacity value. Recent work by Hasche[19] analyzed this question. Using a 10-year wind data set for the Republic of Ireland, alternative sequences of successive years were used to calculate the ELCC for wind. The authors found that with one year of data, it is possible to estimate wind ELCC with an error of -30 percent or +20 percent, compared to the long-term capacity value measured in MW. With 4 or 5 years of data, the deviations are within 10 percent of the long-term capacity value. For example, a wind plant fleet with a long-term capacity value of 20 percent of rated capacity could be estimated to within +/- 2 percent of its long-term value.

For credible analysis of variable generation capacity value, it is essential that consideration be given to the extent to which variable generation output matches load. For this reason, the data requirements for estimating variable generation capacity value can be difficult to manage, particularly over a large geographic scale. Furthermore, the behavior of variable generation over large geographic areas differs substantially than its behavior over small regions.

Figure 7 is from the Eastern Wind Integration and Transmission Study. That study used a large-scale wind database that was derived from a 4-dimensional numerical weather prediction (NWP) model. Because the study examined the impact of extremely large wind energy penetrations in the U.S. portion of the Eastern Interconnection, the wind plant data for the study scenarios could not be supplied from existing wind plants. The NWP was run for a 3-year period, using actual weather data as inputs, to calculate wind speed and wind power on a 2 km square resolution across the interconnection. Large wind plants were modeled by aggregating 30 MW clusters of simulated wind turbines, providing a state-of-the-art estimate of the physical behavior of wind plant performance. The graph shows how the per-unit variability on a 10-minute time-step declines with aggregation of more wind resources over wider and wider footprints associated with the larger penetrations. It is clear from this and other studies of wind plant behavior that

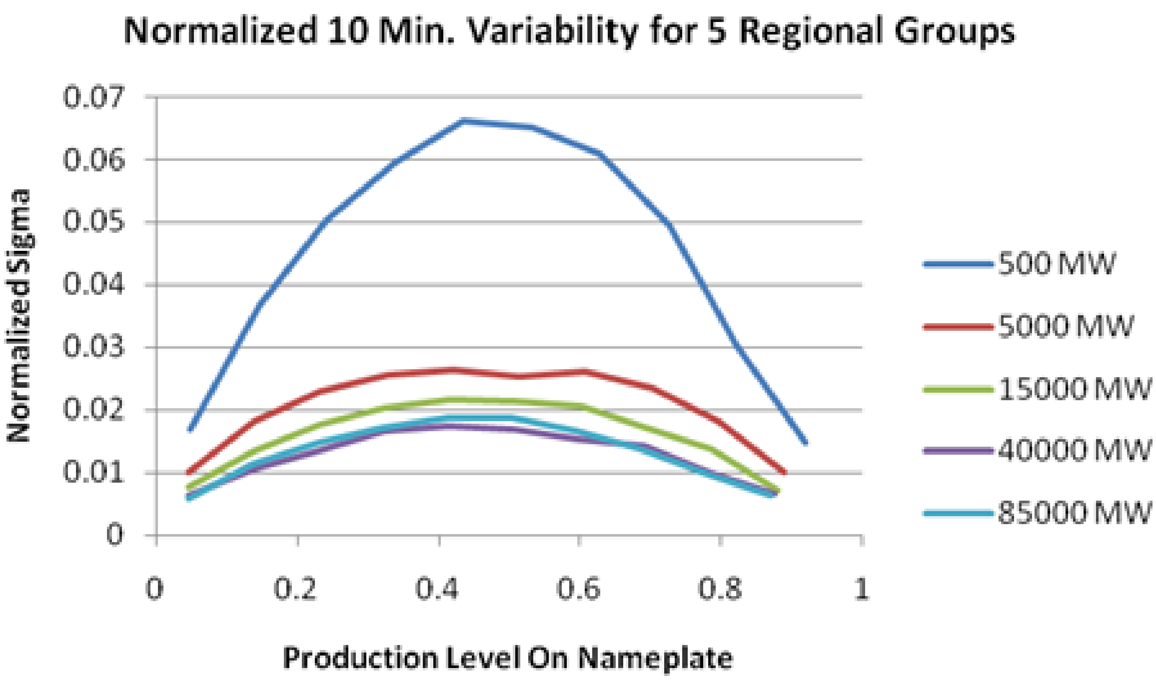
[19] Hasche, B.; Keane, A.; O'Malley, M., *Capacity Value of Wind Power: Calculation and Data Requirements.* IEEE Transactions on Power System. In Press.

wind plant performance is a function of equivalent aggregation of locations, which is the ultimate driver of the wind speed diversity and resulting per-unit smoothing of wind energy.

Because the impact of future variable generation cannot be accurately represented solely by analyzing data from existing plants, there is a benefit to develop and maintain a continental scale database that characterizes the performance of potential future power plants. It has already been demonstrated that these data can be developed and are critical in informing analysis of wind and solar generation for future wind generation penetration scenarios.[20] Much of the technical capability to perform these NWP modeling runs currently exists in national weather agencies and the private sector. Large NWP models and data sets are now developed and maintained by governments to address many concerns, from weather forecasting for the general public, navigation, and severe storm alerts. Data sets are expanded as each new year of data becomes available. A similar dataset for weather-driven variable generation, publically accessible, is needed to help inform system planners about the impact of variable generation on the power system and the contribution to resource adequacy.

As new variable generation power plants are developed, it will become more important to collect relevant performance data from these plants, much as NERC already collects data to inform the Generator Availability Data System (GADS).

Figure 7: Variability of wind generation per unit declines significantly as a function of geographic dispersion.



[20] For example the Western Wind and Solar Integration Study and Eastern Wind Integration and Transmission Study at the National Renewable Energy Laboratory for the Department of Energy.

4. Approximation Methods

Some entities have preferred a simpler approach to calculating the capacity value of variable generation, avoiding the use of a reliability model. Some of these approaches have been benchmarked against the full ELCC calculation and often produce comparable results. Other approaches have not been rigorously compared, to ELCC calculations, but are often used in lieu of the reliability-based methods.

Simplified approaches generally fall into two categories: explicit approximations to reliability analysis or more generalized approaches.

4.1 Approximations to Reliability Analysis

Probably the most famous approximation method is due to Garver (1966). The Garver technique to estimating ELCC was applied to conventional generators and was developed to overcome the limited computational capabilities that were available at the time.

The approach approximates the declining exponential risk function (LOLP in each hour, LOLE over a high-risk period). It requires a single reliability model run to collect data to estimate Garver's constant, known as *m*. Once this is done, the relative risk for an hour is calculated by

$$R' = \mathrm{Exp}\{-[(P-L)/m]\}$$

Where:

P = annual peak load,
L = load for the hour in question,
R = the risk approximation (LOLP), measured in relative terms (peak hour risk = 1)

A spreadsheet can be constructed that calculates R' for the top hourly or daily loads. To apply this method for variable generation the net load (load less variable generation) is used. This approach has been extended by D'Annunzio[21] to use a multi-state capacity representation of wind power plants, which is similar to the multi-block treatment of thermal generation in many reliability models.

Dragoon, et al[22] developed a method that analyzes surplus generation as a random variable and develops the distributional properties of the resulting time series. The z-statistic (ratio of the standard deviation to the mean) of the time series is the primary reliability metric. Once the closed form equation is developed for the given power system, it can be manipulated in a manner that is analogous to the full ELCC calculation: the variable generation can be removed and the load that produces the equivalent z-statistic is the capacity value of the variable generation..

[21] C. D'Annunzio and S. Santoso, "Noniterative method to approximate the effective load carrying capability of a wind plant," *IEEE Trans. Energy Conv.*, vol. 23, no. 2, pp. 544–550, June 2008.
[22] K. Dragoon and V. Dvortsov, "Z-method for power system resource adequacy applications," *IEEE Trans. Power Syst.*, vol. 21, no. 2, pp. 982–988, May 2006

4.2 Time-period Methods

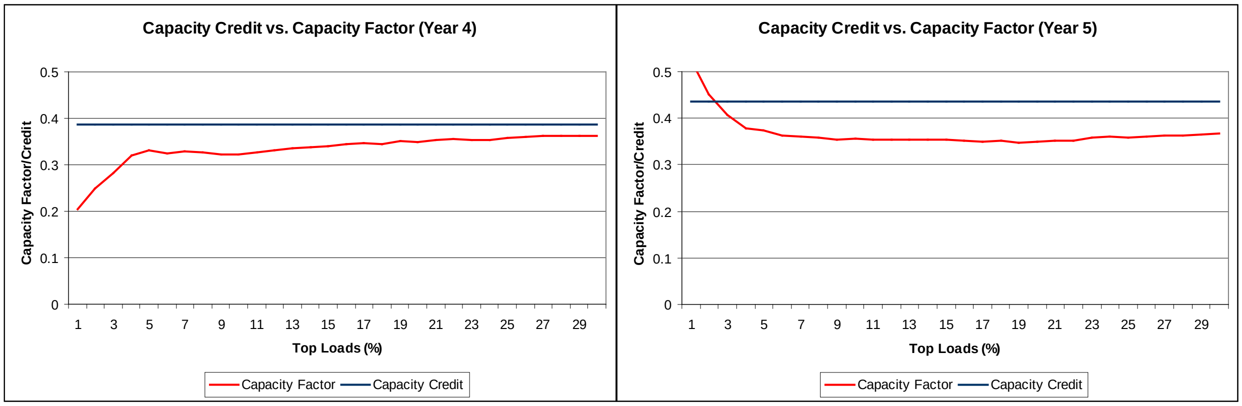
Other methods focus on the variable generation level during system-critical periods. These periods are defined differently, based on the system in question. Perhaps one of the first approaches was developed by PJM, although there are other similar approaches used by ISO New England, the NYISO, MAPP, and others. These will be discussed further in Section 5. However, the basic approach involves two steps:

- Define the relevant time period to use
- Calculate the mean output of the variable generation over that period; or alternatively calculate a percentile or exceedence level of the variable generation over the period

These methods sometimes have a default capacity value that is used until a facility has sufficient operating history to replace the default. In some cases, a moving average is calculated, folding in the actual data as it becomes available. The advantage to these approaches lies in their simplicity, but unless they are benchmarked against a reliability analysis, it is not known how they will compare to ELCC.[23]

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 percent to 30 percent of loads, using an increment of 1 percent. Figure 8 is taken from that study. Although an ideal match was not achieved, the results show that at approximately 10 percent or more of the top load hours, the capacity factor is within a few percentage points of the ELCC.

Figure 8. Example comparison of capacity factor and ELCC for wind



[23] Benchmarking has been successfully carried out in for the NY-ISO, for example.

5. Ongoing Variable Generation Actions

Ensuring sufficient generation resources to meet expected customer demand with adequate reserves to account for forced generation outage in the planning horizon is important for maintaining system reliability. Capacity requirements are implemented differently in different regions of NERC. As variable generation penetration increases, assessing its contribution to resource adequacy in terms of its capacity value becomes more important. However, due to significant variability of wind, solar, and other forms of variable generation, its relationship with load and lack of statistically significant amount of data as well as computational tools and techniques for such analysis, determining capacity value of variable generation facilities with good confidence is difficult. The efforts underway in IEEE task force on Capacity Value of Wind[24] and several other approaches being researched, developed and proposed are described above. However, in many regions, significant amounts of wind generation is being interconnected, and just by the necessity of the marketplace, regions have implemented various methods to determine capacity evaluation methodologies through their respective stakeholder processes. These approaches in some of the ISOs/RTOs are summarized below. As solar and other variable sources grow in prominence on the North American bulk power system, additional efforts will be expended to analyze these technologies also.

5.1 California ISO

For three years, plant output that equals or exceeds 70 percent of period between 4:00 and 9:00 p.m. for Jan-March, and Nov. and Dec.; and between 1:00 and 6:00 p.m. from April through October. Wind projects assigned to one of six wind areas (Tehachapi, San Gorgonio, Altamont, Solano, Pacheco Pass, and San Diego). Diversity benefit adder if wind area capacity credit higher than individual wind project. Various adjustments if wind project operating less than three years.

5.2 BPA

BPA has decided to use a zero value for wind capacity for both winter and summer

5.3 SPP

SPP assigns monthly wind capacity value as 85th percentile of the wind generation during the highest 10 percent of the load hours using up to 10 years of data. Capacity values of wind plants in SPP area is typically 10 percent of their rated capacity.

5.4 ERCOT

Wind generation is included in capacity reserve margin calculations at 8.7 percent of nameplate capacity, based on effective load-carrying capability. In the Monte Carlo approach used by

[24] Keane, Milligan, Dent, Hasche, D'Annunzio, Dragoon, Holttinen, Samaan, Soder, O'Malley, "Capacity Value of Wind Power". IEEE Transactions on Power Systems. In Press.

ERCOT, wind and load data are not synchronized from the same year, and random draws are made from a multi-year wind data base and matched to a potentially different load year. ERCOT is doing additional ELCC analysis.

5.5 ISO New England

Summer capacity credit for variable energy projects qualified in the Forward Capacity Market is the average of median net output from 2:00 PM to 6:00 PM for June to September in previous five years. For resources that are 'energy only' and not part of the Forward Capacity Market, they will be reported at their nameplate rating. However, they will not be included in either reserve margin calculations or other reliability studies.

5.6 MISO

The MISO uses the ELCC method. The most recent analysis found that wind capacity value in the MISO footprint for existing wind plants is 8 percent of rated capacity. MISO has a Loss of Load Expectation Working Group that will continue to analyze resource adequacy and the contribution of wind and other variable generation in its footprint.

5.7 New York ISO

In New York ISO, summer capacity credit for existing wind generation plants is determined by their capacity factor between 2:00 PM and 6:00 PM during June, July and August of the previous year. Similarly, winter capacity credit is determined by the plant's capacity factor between 4:00 PM and 8:00 PM during December, January and February from the previous winter. New wind projects are assigned a summer capacity of 10 percent and winter capacity credit of 30 percent of their nameplate capacity, and these values are used until operating data from the plant becomes available.

5.8 PJM

Capacity credit for wind generation plants in PJM is their average capacity factor for hours ending 3:00 PM to 6:00 PM (local time) in June, July and August. The capacity credit is a rolling three year average of the most recent years. For new wind generation plants a class average of 13 percent of nameplate capacity is used as an initial value which is based on the class average for all existing wind generation plants. As actual data become available from the operating wind plant, it replaces the 13 percent default value.

5.9 Ontario IESO

To model wind resources in mid-to-long term resource adequacy assessments (beyond the 33-day time horizon), the IESO uses an estimated wind capacity contribution during peak demand hours. This model captures wind output during the top 5-contiguous daily peak demand hours for the winter and summer seasons, as well as monthly shoulder periods. Two sets of wind data are considered: simulated wind data over a fixed 10-year history, and actual wind farm output data collected since March 2006. A conservative approach is employed, which selects the lesser value of the two data sets (simulated vs. actual) for each winter/summer season and shoulder period month.

The model described above is applied both deterministically and probabilistically depending on the resource adequacy model being used. For the 18-Month Outlook and seasonal assessments, wind capacity contribution is represented deterministically, by selecting median values observed during the winter and summer seasons and shoulder period months. For Comprehensive/Interim Reviews of Resource Adequacy and other annual assessments, probability distributions are constructed for the winter and summer seasons and shoulder period months. These distributions are used as inputs into the GE-MARS model, which randomly generates a probability value to determine wind capacity contribution to the forecast daily peak demand.

5.10 Québec Balancing Authority Area

Capacity credit for wind plants in Québec was estimated using a variant of ELCC method. A custom-made Monte Carlo Simulation Model where load and wind generation data are chronologically matched on an hourly time-step over 36 years period was used to estimate Québec's wind capacity contribution. Wind power time series were obtained from a diagnostic method using meteorological data available from weather stations, extrapolated at the specific wind generation sites. These data were supplemented by in depth analysis of fourteen critical extreme cold weather events, using high resolution numeric weather prediction models. It was established that the capacity credit of wind power is likely to be 30% of its nameplate capacity for winter peak period. For summer period, wind capacity is de-rated.

6. Conclusion and Recommendation

The ability to accurately assess generation adequacy and quantify the risk of not meeting load has always been important. As wind, solar, and other variable generation sources increase, the affect these sources have on overall reliability and the way they contribute to resource adequacy is an important emerging issue.

6.1 Metric

Reliability-based methods of measuring system adequacy are not new, nor are they unique to variable generation. The value of these methods will increase with the integration of large amounts of variable generation. Because variable generation resources have a variable and stochastic nature, methods that can account for these characteristics are not only appropriate, they are necessary to obtain an accurate risk-based assessment of resource adequacy. We therefore recommend the use of LOLP, LOLE, or related metrics for resource adequacy calculations and for determining the capacity contribution of VG an all generators.

There are several reliability-based approaches that can be used to calculate the effective load-carrying capability of a power plant. Each of these has advantages and disadvantages, and NERC may want to convene a group at some future date to delve into the differences and perform some comparative analysis as variable generation use increases. The traditional approach is based on the LOLE of 0.1 days/year as the reliability target. This approach considers only the peak hour of the days that have significant LOLP. This is typically a relatively small number of days because most of the year there is a surplus of capacity. Variable generation that generates little or no power during these times will have a low capacity value, even though lots of energy may be produced at other times. The daily LOLE approach does not measure risk of insufficiency during the non-peak hours of the peak days. A significant daily LOLE means that during the day there is some probability of insufficient generation, but the metric does not indicate the duration of the potential insufficiency, nor does it indicate the potential energy shortfall. When this metric is applied to variable generation, it can take into account the change that variable generation induces to the peak that must be met by the non-variable generation. In some cases this may change the time of day that the LOLP is at its maximum, effectively shifting the peak hour (after accounting for the variable generation).

A LOLH metric considers all hours during which there may be a risk of insufficient generation. With high penetrations of variable generation, this may be an advantageous metric because of the variability of these resources. The daily LOLE metric is coarse: it only considers one hour a day. The LOLH metric looks at each hour. This provides a more accurate assessment of adequacy in the sense that all hours are examined by the metric. However, unlike the daily LOLE, there is no generally accepted hourly target. For example, 2.4 hours/year is not the same as 0.1 days/year. Additional analysis is required to determine the relationship between LOLE and LOLH reliability targets.

Neither daily LOLE nor LOLH provide information about how much energy shortfall is possible. That can be provided by expected unserved energy (EUE). As is the case with LOLH, there is no generally-accepted target level for EUE. As more energy-limited variable generation is added to the system EUE or a related metric appears to have significant value for resource adequacy assessments.

These metrics do have common elements. They are all probabilistic metrics that explicitly consider risk. All of these methods begin by taking the full year (or multiple years) into account, but after performing the risk calculation (LOLE, LOLH, or EUE) most of the year gets thrown out so that the analysis can then focus on the system-critical times when there is significant risk of generation shortfall. Non-peak times of the year may have significant LOLP (LOLH or EUE) if a large amount of capacity is unavailable because generators are undergoing scheduled maintenance.

Recommendation: *Based on the emphasis that prior work has placed on a daily LOLE and target of 0.1 days/year, additional research to equate traditional reliability targets (such as 0.1day/year) to alternative metrics is recommended. As adequacy studies are performed, we also recommend comparisons of results based on these alternative metrics. We envision more widely-adopted energy-related reliability metrics and targets as the share of variable generation increases in the power system. We also encourage transparency in the reporting of these results.*

6.2 Multi-area Reliability and Adequacy

There appears to be variations in the way that imports, exports, and emergency measures are handled in reliability calculations. Some of this is to be expected, based on differing approaches and rules in different power pools, and the differing nature of the capacity and energy delivery options between regions. In addition, different assumptions regarding interconnected resources would be expected to vary, based on the problem that is under evaluation. However, a suite of consistent and common approaches would be desirable and aid in comparisons among systems, and full transparency of these issues is critical.

Recommendation*: Alternative approaches and assumptions regarding the treatment of interconnected systems should be transparent to the analysis, and the development one or more common approaches for handling the impact of interconnected systems in the reliability assessments will be useful. Existing committees such as the Generation and Transmission Reliability Planning Models Task Force, or other groups may develop improved methods for modeling or reporting these results. These reliability considerations will have an impact on the relevant footprint that is used to calculate the contribution that variable generation makes towards resource adequacy (capacity value). The assumptions regarding the appropriate electrical footprint used in the reliability analysis will have a profound impact on resource adequacy in general, and variable generation capacity value in particular.*

6.3 Alternative Approaches

Power system planners have adopted other metrics for resource adequacy. One common one is the Planning Reserve Margin. Unless the Planning Reserve Margin is derived from an LOLP study, there is no way to know what level of system risk is present. This is because some generators have higher forced outage rates than others. Therefore, one system with a 15 percent

Planning Reserve Margin may not be as reliable as another system even though it also has a 15 percent Planning Reserve Margin.

Recommendation: *Planning Reserve Margin levels should be benchmarked with, or derived from, an LOLP or related approach to resource adequacy. This should be done periodically to ensure that any correlation between a 0.1days/year target (or other adopted target) and a given Planning Reserve Margin do not change as a result of an evolving resource mix. As the penetration of variable generation increases, the PRM metric will contain less useful information because of the divergence of variable generation rated capacity and capacity contribution to resource adequacy.*

There are existing simplified approaches to calculate wind capacity value. These can be easily extended to cover other forms of variable generation. In general, these methods calculate the resource's capacity factor over a time period that corresponds to system peaks. These approaches can provide a reasonably good, simple approximation to capacity value. However, system characteristics in some cases may result in a mismatch between a rigorously calculated ELCC and a peak-period capacity factor as an approximation to capacity value.

Recommendation*: Simplified approaches should be benchmarked and calibrated to the rigorous ELCC calculations to ensure the validity of the approximation.*

6.4 Data

Calculating capacity value for existing variable generation sources requires chronological generation data that is synchronized with load data and other relevant system properties. There is a need to track the performance of variable generation so that the contribution of these various technologies to resource adequacy can be better understood. Existing data bases such as the NERC GADS could perhaps be extended to track this data, which would be useful in helping to better understand variable generation performance and operational issues (addressed by other work streams of the IVGTF). NERC already collects data to inform the GADS database. Although it is more data intensive than the GADS process, operational data from variable generation over the next several years will be extremely valuable in the assessment of capacity value and operational issues surrounding the use of variable generation.[25]

Recommendation: *NERC should design and implement a way to collect high-quality variable generation data that would help inform calculations of capacity value. Data could be archived either by NERC or other entity such as a DOE laboratory (NREL is already doing this for many wind plants in the U.S.), as appropriate. The development of such a database should consider defining relevant time periods for the variable generation data (for example summer and/or winter peak periods) that may correspond to some of the simplified methods discussed in this report. However, it must be recognized that there can be significant LOLP risk during non-peak periods under some conditions, and the design of the database and subsequent collection effort should consider this. Because actual variable generation output can be curtailed because of transmission congestion or other factors, data collection on these issues is also recommended.*

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[25] To support this action, NERC's Generation Availability Data System (GADS), which is a voluntary data collection system, can be a source of some of the data, though other sources may also be available.

Variable generation is anticipated to increase substantially in the North American grid. It will be critical to provide ongoing evaluation of the potential impacts of new variable generation resource on the grid. Because prospective variable generation plants, by definition, do not already exist, obtaining data that can describe the likely behavior of future plants is critical for a number of reliability, adequacy, and integration tasks that are performed in the planning cycle. It is critical to ensure that variable generation data and load are synchronized because weather is the principle driver for load and for variable generation output. Specific locations of future variable generation may not be known with certainty, and to evaluate the likely impacts, multiple scenarios may need to be evaluated. Therefore, it is necessary to develop and maintain a public database of wind and solar estimated (future) production. Large-scale NWP models or solar radiation and cloud cover models can be used to provide high resolution wind power and solar power data. The value of this type of dataset has been shown in the Eastern Wind Integration and Transmission Study (EWITS) and the Western Wind and Solar Integration Study (WWSIS).

Recommendation*: NERC should request that government agencies like the DOE, working with NOAA/NCAR develop annual high-resolution, modeled wind power and solar power data on 10-minute time scales (or faster, as technology allows) and 2 km (or smaller) geographic grids. These data should be accessible over the internet for power system planners and other to access freely. Each year, the data from the most recent year should be added to the database. This will help inform power system engineers and analysts about capacity contributions of potential future variable generation resources and other important operational characteristics. Accompanying the 10-minute wind and solar data, NERC should consider collecting 10-minute load data to support reliability and other analyses.*

6.5 Education

Based on the experience of many participants of the IVGTF Task Force 1.2, it seems apparent that the workings of LOLP, ELCC, and related reliability approaches are not always well understood.

Recommendation: *NERC should facilitate the dissemination of information about how LOLP-related reliability and adequacy calculations perform and what they measure.*

Appendix A: Application to Variable Generation and Results from Recent Analyses (WWSIS and EWITS)

The National Renewable Energy Laboratory (NREL), under the sponsorship of the U.S. Department of Energy, recently completed two large-scale studies of high penetrations of wind. The first study is the Eastern Wind Integration and Transmission Study (EWITS), which was collaboration between NREL, the Midwest Independent System Operator, Ventyx, AWS TrueWind, and the Joint Coordinated System Plan. The second study added solar integration, but did not analyze transmission needs in depth. The Western Wind and Solar Integration Study (WWSIS) was performed on the WestConnect region of the Western Interconnection, modeling all of the U.S. portion of WECC. As a part of both studies, the capacity contribution of wind was assessed, and the WWSIS analyzed the capacity contribution of concentrating solar plants, and photovoltaic plants.

The discussion that follows is taken from the WWSIS report, with later discussion summarizing some of the EWITS results.

A.1 Example calculations from the Western Wind and Solar Integration Study (WWSIS)

As noted above, the historical calculation was carried out using the daily peak load, and ignoring all other hours of the day. This is very important to variable generation. If a particular resource produces 100 MW of generation for 23 hours of the day but only generates 10 MW at the hour of the daily peak then the calculation will see it as just 10 MW. It will have no greater capacity value than a generator that puts out 10 MW for every hour of the day. This explains why the capacity value of wind is often much lower than traditional thermal generation. Likewise, a device that can consistently generate 100 MW at the daily peak but zero MW the rest of the day will the same capacity value as a unit that produces 100 MW all day long.

One shortfall of this method is that with the capacity output changing hourly it is possible to have capacity shortages at times other than the peak hour. This could occur if a resource was generating 100 MW in the peak hour but only 10 MW in the next hour when the load only dropped 30 MW.[26] In order to capture this effect the model was adjusted to look at all 24 hours in the day. In addition to calculating the number of hours that the system might be short, which is a measure used in some regions, the model counted up the number of days in which an outage occurred at any time of the day. In this manner all shortages are captured regardless of the time of day and all capacity levels are also considered. This method also captures the synergy between the capacity impacts of different types of intermittent renewable generation. PV and wind generation tend to occur more during off-peak periods which reduces their capacity value. Concentrating Solar Plants (CSP) with storage, on the other hand, can be shifted to reduce the peak loads. This then pushes the relative peaks into the shoulder hours, allowing the PV and wind to have more of an impact. This will be shown in the results.

[26] In the examples and discussion that follow, we adapt sections of the WWSIS system adequacy chapter (reference) to illustrate the application of the LOLP-based resource adequacy calculations to variable generation.

In addition to the daily and hourly indices, the program also determined the magnitude of any shortages so that total energy shortfalls could be calculated. This value will differ from the value calculated in the production simulation analysis. A reliability analysis assumes that all capacity not on outage is available to serve load. Most of the shortages, or unserved energy, in the production modeling were due to forecast errors that caused units to not be committed and available for dispatch.

One aspect of capacity value is where the unit is located. A perfectly reliable generator located behind a transmission constraint may not add any capacity value to the system. In this analysis we wanted to capture the capacity value of the renewable generation based on their generation profiles, the area load profiles and the characteristics of the rest of the generators in the study area. In order to do that it was assumed that there were no transmission constraints within the study area for the reliability analysis. In this way the capacity values will not be penalized due to transmission constraints.

The study area has thousands of megawatts of interconnections to the rest of WECC. In order to calculate non-zero reliability indices these ties were set to zero. This resulted in an LOLE index of 3.58 days/year for the single-area, isolated study footprint. This provided a good starting point for the capacity value calculations.

The question "How much capacity is a wind plant worth?" can be answered in a few different ways. It could be compared to the number of gas turbines or coal plants that would be needed to get the same reliability impact. Alternatively, it could be a measure of the amount of peak load increase that could be allowed while still maintaining the original reliability level. Or a third measure would be how much "perfect capacity" would be needed to achieve the same level of reliability. All of these measures produce similar results. This analysis used the "perfect capacity" measure. An advantage of perfect capacity is that it is independent of forced outage rate, unit size and load profiles which affect the other measures.

Figure 9 shows how the daily LOLP of the study footprint improved with the addition of a series of 500 MW blocks of perfect capacity. It is important to note that the scale on the y-axis is exponential. Figure 10 shows the results of multiple simulations with various combinations of renewable generation added, and then plotted on the same curve as the previous figure. Each of the three types of generators was examined separately, as well as combined with the others for different levels of penetration. For example, the three red triangles represent the impact of wind generation alone at the 10 percent, 20 percent and 30 percent penetration levels.

Figure 9: Study Area Risk versus Capacity Additions

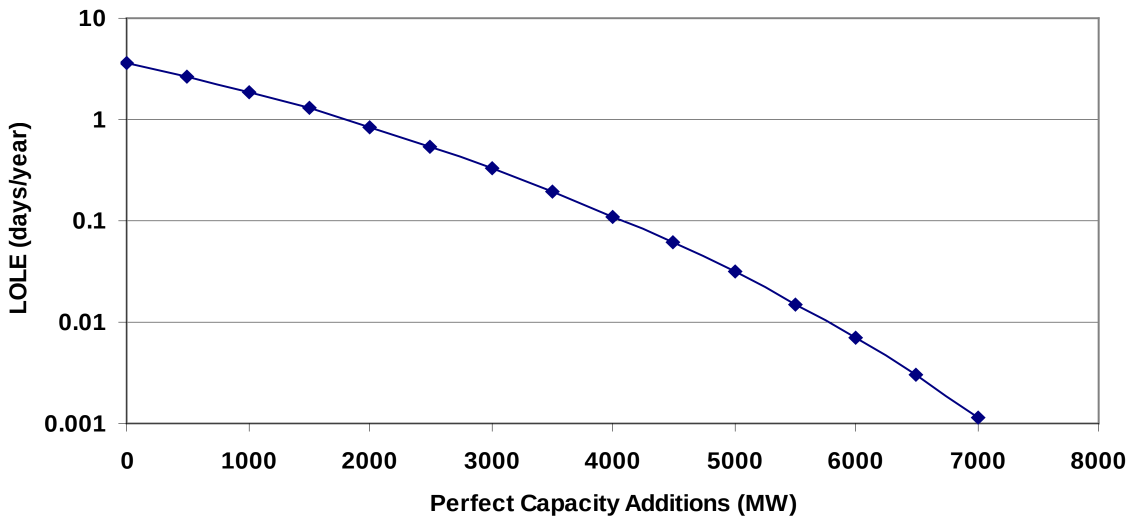


Figure 10: Study Area Risk with Renewable Additions

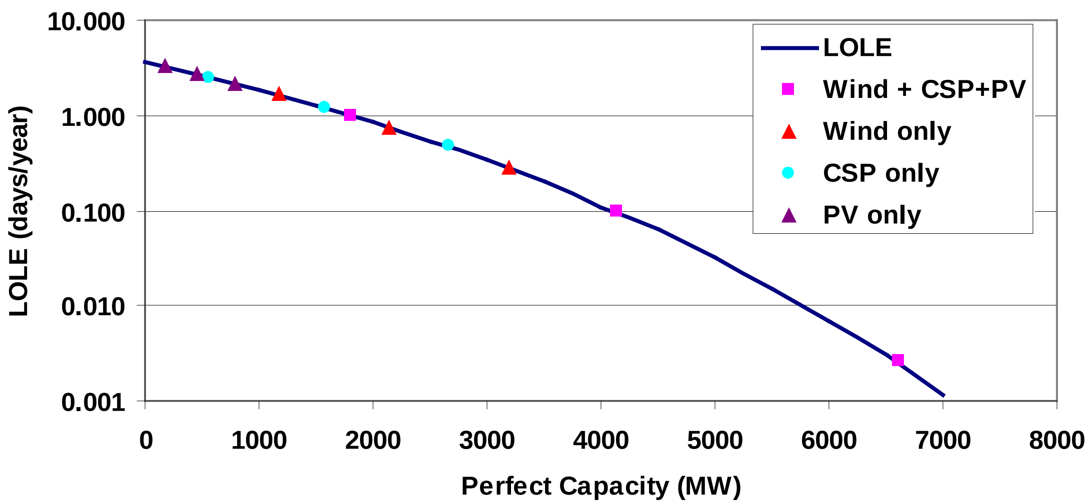


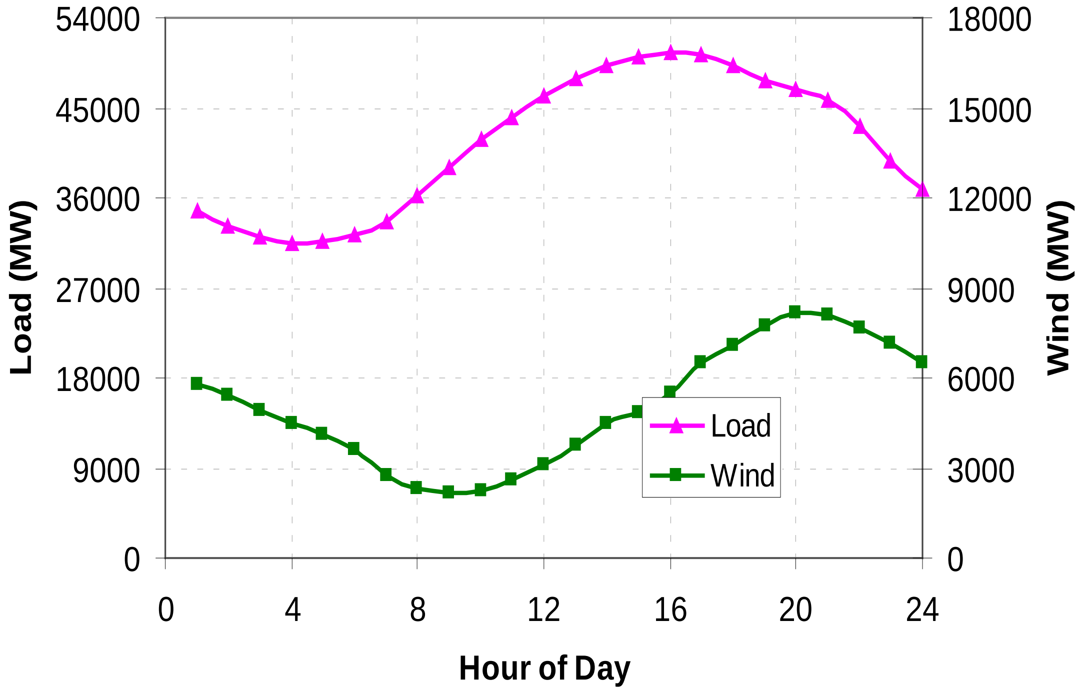
Table 1 shows the nameplate capacity of the wind, CSP and PV generation added in the three levels of penetration. Table 2 shows how the capacity values derived from Figure 10 compare to their nameplate ratings on a percentage basis. It is clear that there is significant variation in capacity value among the different types of renewable generation.

Table 1: Renewable capacities by type				
Penetration	**Total Renewables (MW)**	**Wind Capacity (MW)**	**CSP Capacity (MW)**	**PV Capacity (MW)**
10% wind, 1% solar	**11,490**	**10,290**	**600**	**600**
20% wind, 3% solar	**23,350**	**19,950**	**1,700**	**1,700**
30% wind, 5% solar	**35,740**	**29,940**	**2,900**	**2,900**

Table 2 Renewable capacity values by type, 2006 shapes, perfect capacity, daily LOLE.				
Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
10% wind, 1% solar	15.8%	11.4%	92.6%	28.6%
20% wind, 3% solar	17.7%	10.8%	93.3%	26.9%
30% wind, 5% solar	18.5%	10.7%	92.2%	26.9%

Timing is everything, Figure 11 shows the average daily profile of the study area load and wind generation for the 30 percent scenario in the peak month of July. Although the 30 percent in-Area scenario includes 30,000 MW of wind plants, their total output is less than 6,000 MW at the peak hour.

Figure 11: Hourly average wind and load shape



This can be compared to the curves in Figure 12 that shows the average CSP and PV outputs. The CSP (with storage) had an average output of about 2,400 MW and the PV was about 800 MW at the peak load hour. Both of them had an installed capacity of 2,900 MW.
Figure **13** shows the wind and solar energy production by month for the 2006 shapes. When the daily and monthly profiles are compared to the load it is not surprising that the wind capacity value is low. The PV value is limited by the fact that the solar energy peaks at noon and has dropped significantly by the time that the load reaches its peak in late afternoon. The storage on the CSP allows the output to be held near its full rating later in the day and this is what contributes to its high capacity values.

Figure 12: Average solar and load shapes

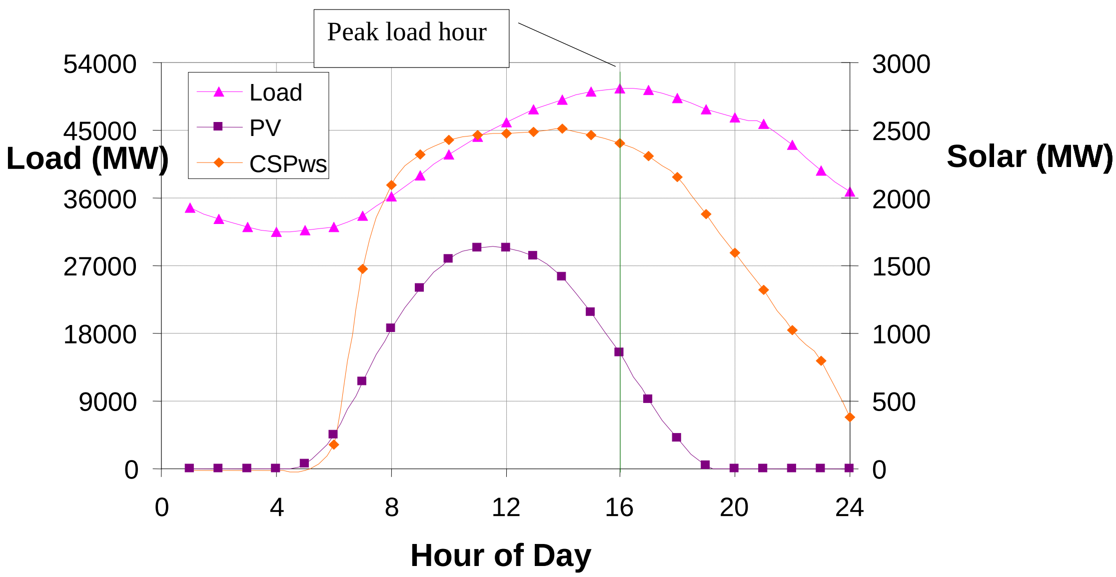
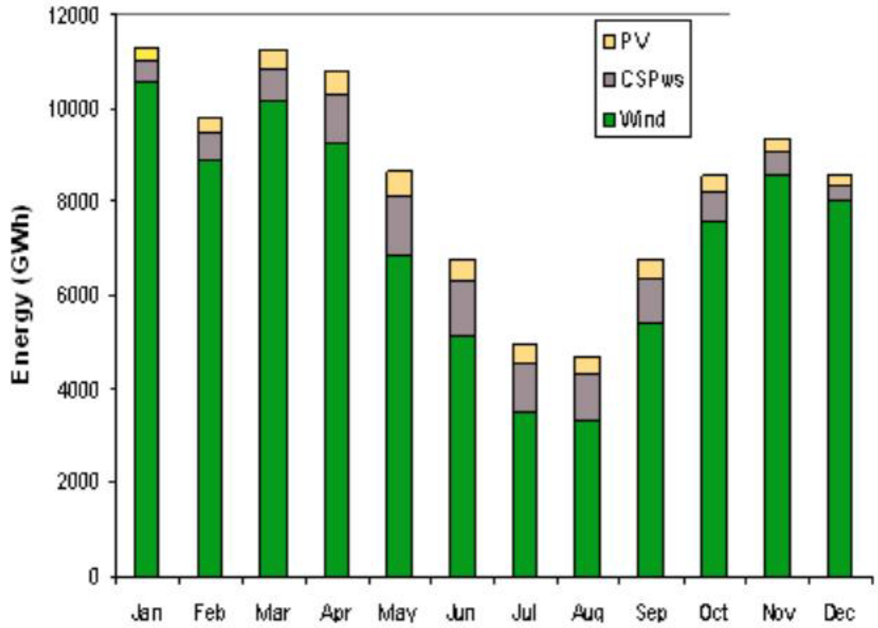


Figure 13: Study area total monthly wind and solar energy



A.2 Hourly and Unserved Energy Measures

The same type of analysis can be done using the hourly LOLP index and the unserved energy. Just as the daily LOLP analysis calculated the expected number of days of shortage, applying the same calculations to all of the hours of the day can calculate the expected number of hours of shortage. If each hour of shortage is combined with the corresponding magnitude of the shortage then the expected unserved energy for the year can be determined. Wind and solar generation can then be added to the system to determine the equivalent amount of perfect capacity required to have the same impact on the hourly and unserved energy indices. Figure 14 and Figure 15 show the curves corresponding to these calculations. Table 3, Table 4, and Table 5 are the companion capacity values.

Figure 14. Study area risk in hours/year

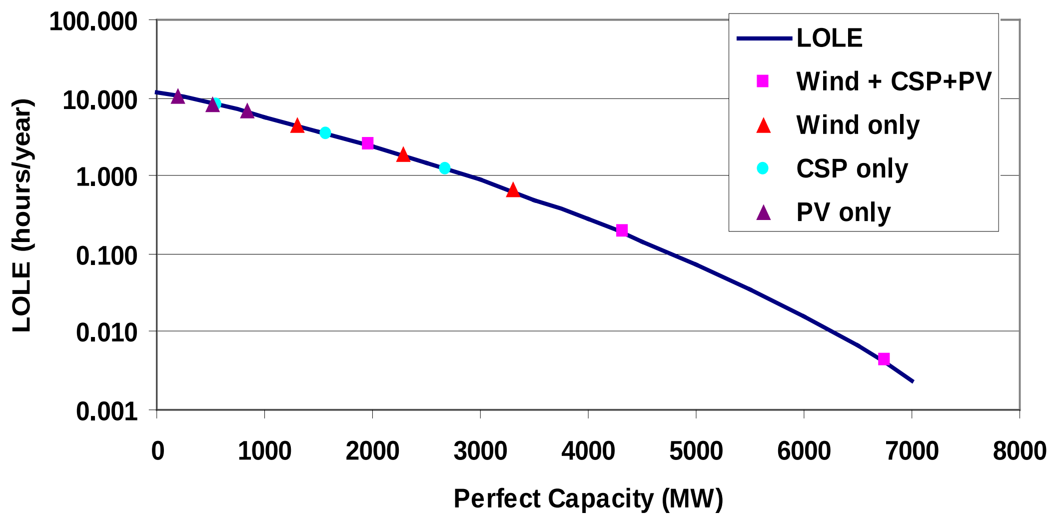


Figure 15: Study area risk in unserved energy

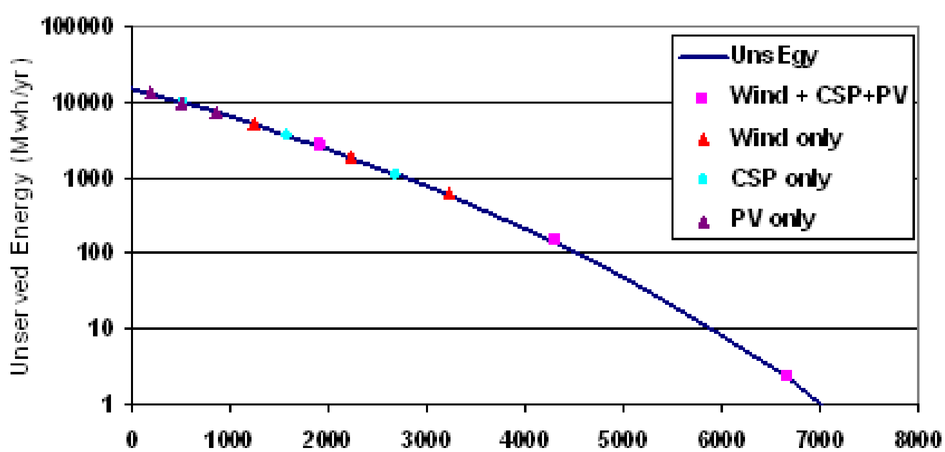


Table 3 Renewable capacity values by type, 2006 shapes, perfect capacity, hourly LOLE				
Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
10% wind, 1% solar	17.1%	12.6%	90.8%	32.1%
20% wind, 3% solar	18.5%	11.5%	92.7%	30.3%
30% wind, 5% solar	18.9%	11.0%	92.6%	29.0%

Table 4 Renewable capacity values by type, 2006 shapes, perfect capacity				
Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
10% wind, 1% solar	16.6%	12.1%	88.5%	33.2%
20% wind, 3% solar	18.4%	11.2%	92.6%	30.0%
30% wind, 5% solar	18.6%	10.8%	92.6%	29.3%

Table 5 Renewable capacity values by type, 2006 shapes, perfect capacity, average across indices				
Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
10% wind, 1% solar	17%	12%	91%	31%
20% wind, 3% solar	18%	11%	93%	29%
30% wind, 5% solar	19%	11%	92%	28%

A.3 Capacity Value Variation by Scenario

The intent of this analysis was to capture the capacity value of the renewable generation based on their generation profiles, the area load profiles and the characteristics of the rest of the generators in the study area. In order to do that it was assumed that there were no transmission constraints within the study area for the reliability analysis. In this way the capacity values are not penalized due to transmission constraints. The 2006 analysis was repeated for the three different siting scenarios.[27] Although the megawatts in each area and in total changed between the scenarios, particularly for the wind generation, there was very little change in the capacity value as shown in Table 6. The results are shown graphically in Figure 16, Figure 17, and Figure 18.

Table 6: Renewable capacity values by type, perfect capacity, daily LOLE, by Scenario

Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
In-Area				
10% wind, 1% solar	15.8%	11.4%	92.6%	28.6%
20% wind, 3% solar	17.7%	10.8%	93.3%	26.9%
30% wind, 5% solar	18.5%	10.7%	92.2%	26.9%
Local Priority				
10% wind, 1% solar	16.5%	11.4%	92.6%	28.6%
20% wind, 3% solar	18.7%	11.3%	93.3%	26.9%
30% wind, 5% solar	18.8%	10.5%	92.2%	26.9%
Mega Project				
10% wind, 1% solar	18.5%	13.0%	91.6%	25.8%
20% wind, 3% solar	19.0%	11.9%	94.1%	24.7%
30% wind, 5% solar	19.3%	10.0%	92.8%	24.8%

[27] Three scenarios were developed for this study. The Mega-project scenario placed the wind generation at the highest capacity factor sites, concentrating much of the development in Wyoming and requiring significant transmission build-out. The In-Area scenario assumed that wind development would occur locally, within each state to fulfill renewable targets. This required minimal new transmission. The final case is the Local Priority scenario, a mix between the first two scenarios.

Figure 16: Wind capacity values by scenario, 2006 shapes, perfect capacity

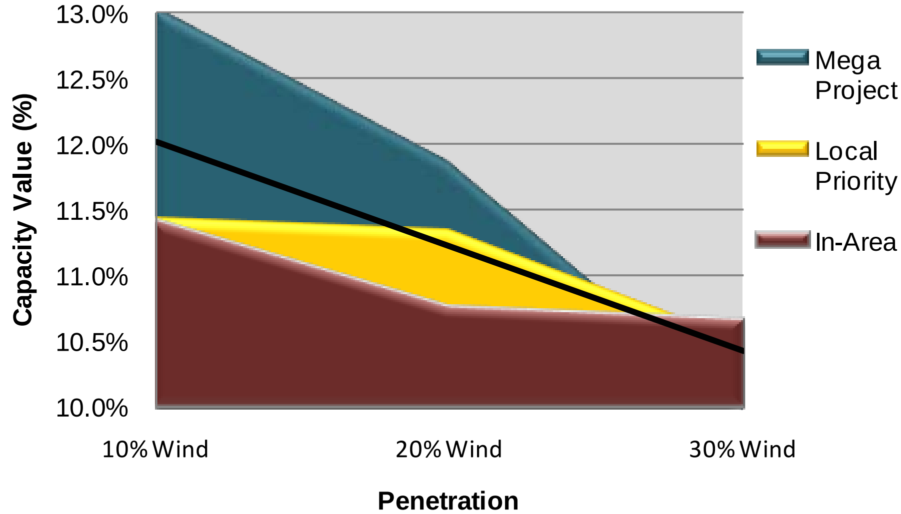


Figure 17: CSP with storage capacity values by scenario, 2006 shapes, perfect capacity

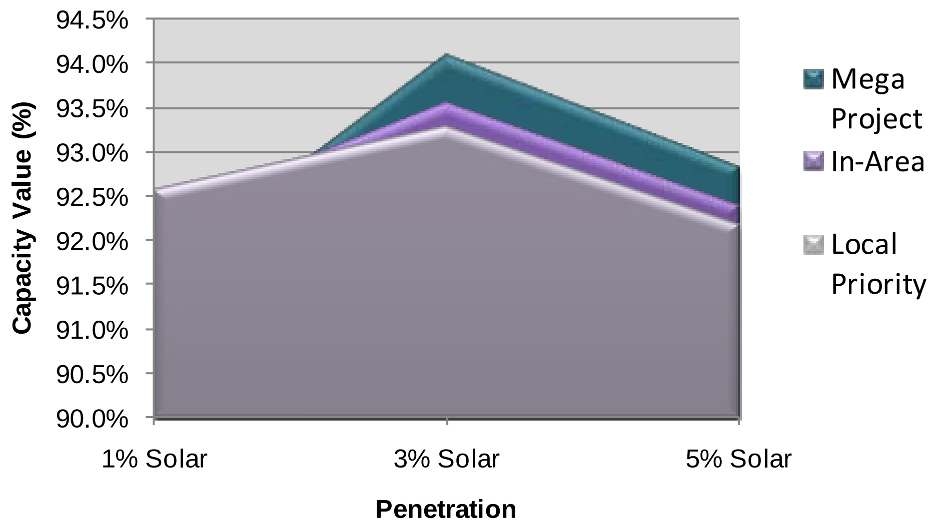
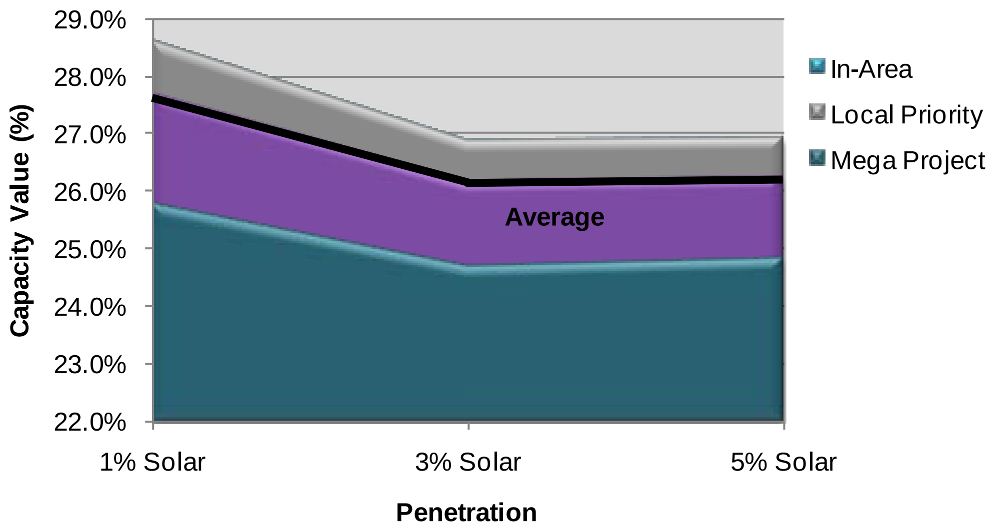


Figure 18: Photovoltaic Capacity values by scenario, 2006 shapes, perfect capacity



A.4 Capacity Value Variation by Shape Year

The results shown so far were based on the 2006 load and weather shapes. The In-Area analysis was also done using the shapes from 2004 and 2005. Figure 19 shows the monthly energy variation by type for the three years for the In-Area scenario. The green bar indicates the wind energy, the orange is for the CSP and the pink is for the PV plants.

Figures 20-23, show the variations in capacity value for the individual generation types and well as the combined total for the three shape years. There is some year-to-year variation but it does not appear to be significant.

Figure 19: Annual and monthly variation in renewable energy

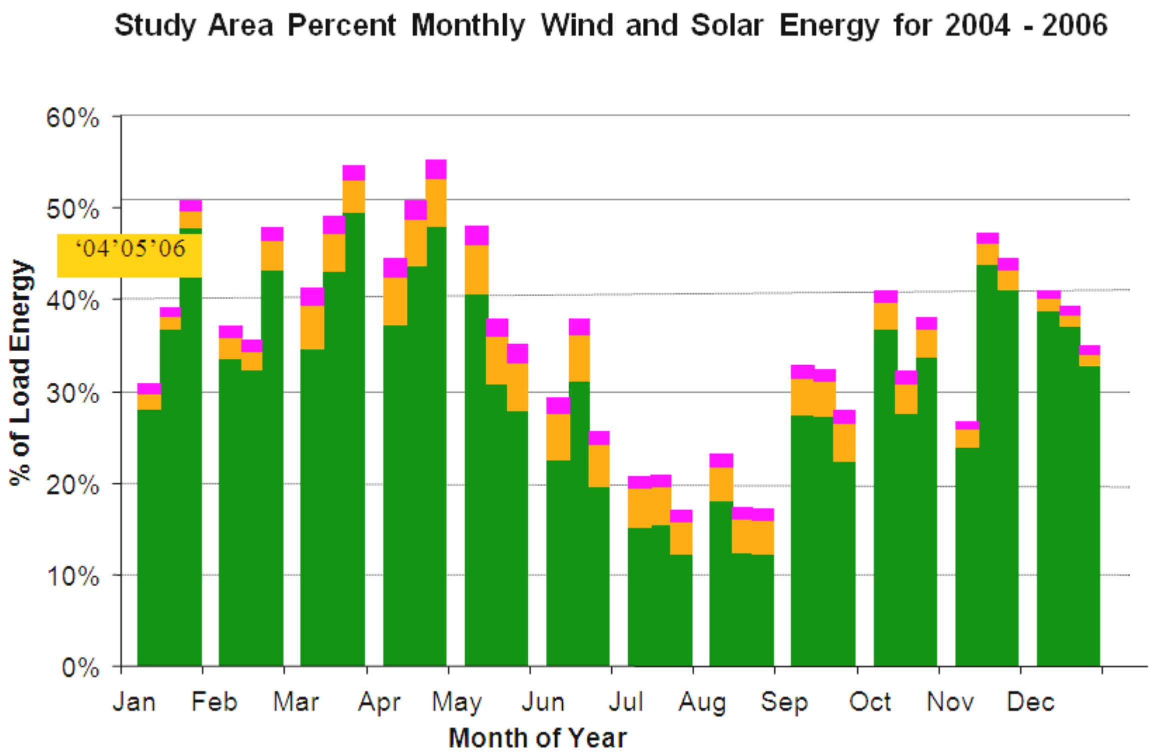


Figure 20: Capacity value for wind, perfect capacity, daily LOLE, all years

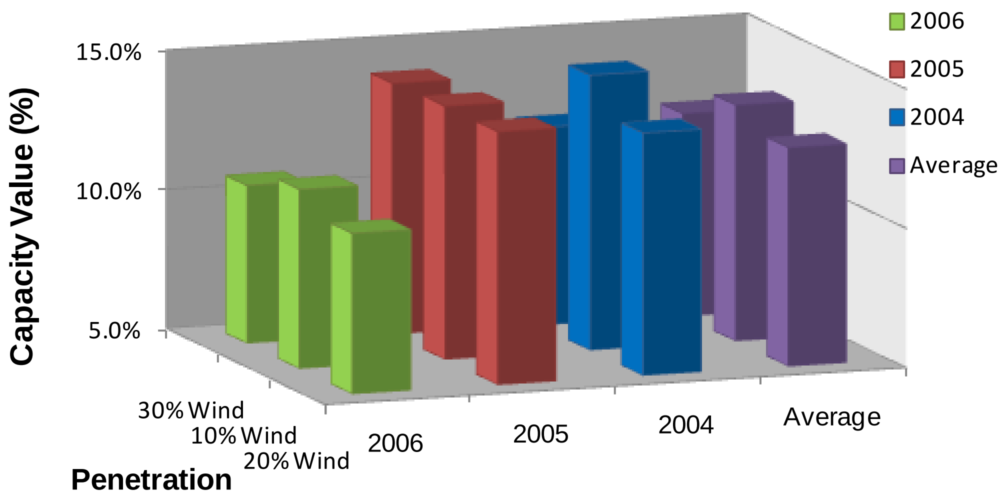


Figure 21: Capacity value for CSP with 6 hours of storage, perfect capacity, daily LOLE, all years

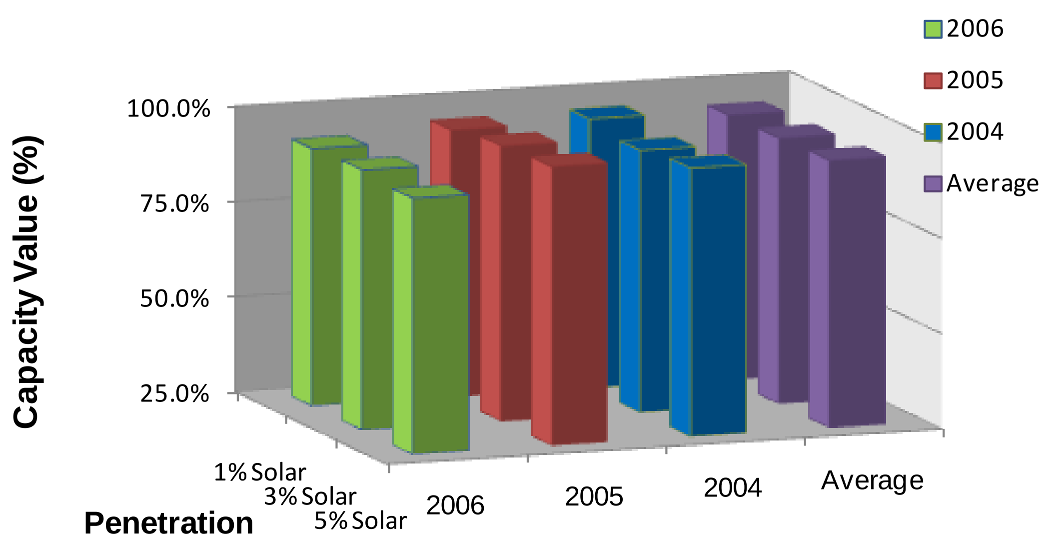


Figure 22: Capacity value for solar with 6 hours of storage, perfect capacity, daily LOLE, all years

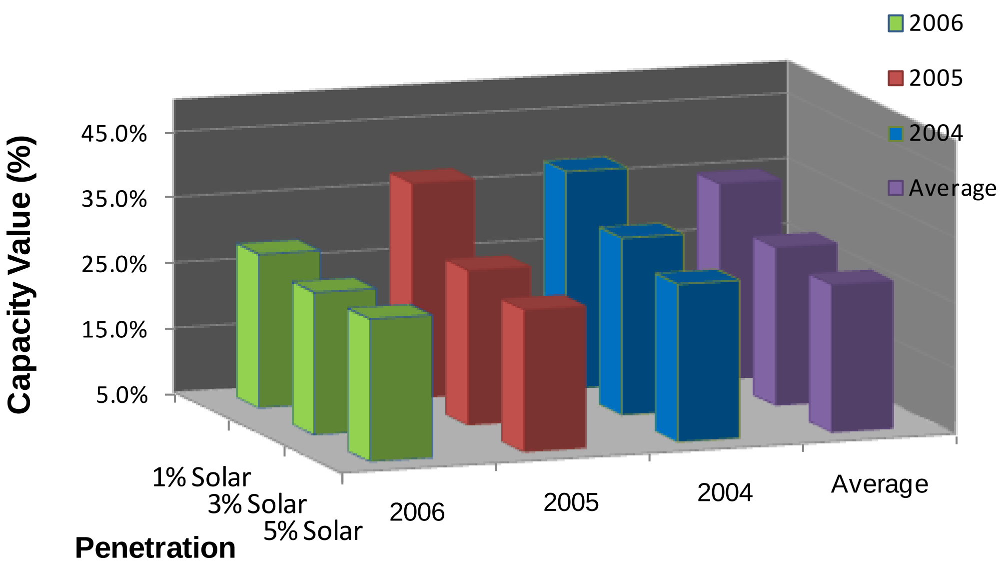
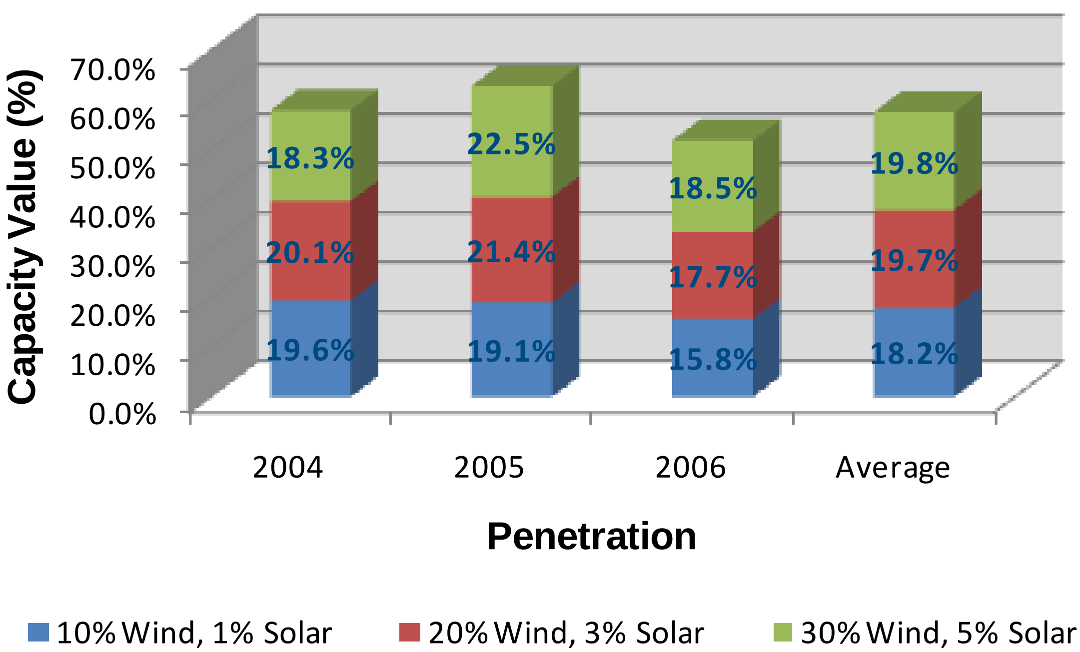


Figure 23: Combined capacity value for wind, CSP and PV, perfect capacity, daily LOLE, all years



A.5 Comparison to Other Measures

This analysis has equated the renewable generation to the amount of perfect capacity that would produce the same result. Other studies have considered the amount of equivalent generators or increased load that could be carried. This section will compare the measures.

If a unit is large relative to the size of the system then this will distort its capacity value. However, if the unit's capacity is small relative to the system size then its effective capacity is typically estimated as its nameplate capacity times one minus the forced outage rate. For example, a 100 MW gas turbine with a 5 percent forced outage rate would have an effective capacity of 95 MW. Therefore, to convert the perfect capacity values to an equivalent capacity of gas turbines with 5 percent forced outage rates you would divide the previous values by 0.95. Similarly, to convert the perfect capacity to equivalent units with a 10 percent forced outage rate you would divide by 0.90. Referring back to the "wind only" value for the 30 percent scenario in 100 MW of nameplate wind generation would have a value of 10.7 MW of "perfect" capacity, Figure 19. This would correspond to 11.3 MW of capacity when compared to gas turbines or 11.8 MW of capacity when compared to a unit with a 10 percent force outage rate.

Another method that is used in the industry is the effective load carrying capability or ELCC. In this case, after a generator is added to the system, the peak load is increased until the risk is back to its original value. When the peak load is increased, the other loads are also increased proportionately. Therefore, if the annual peak load is 1000 MW and another day has a peak of 900 MW, when the peak is increased by 100 MW, or 10 percent, the other day is only increased by 90 MW. This has the effect of increasing the value over the perfect capacity method since 100 MW of perfect capacity is worth 100 MW in every other hour. For comparison purposes we examined the case with 2006 shapes, 30 percent In-Area scenario. The perfect capacity value for all of the renewables was 6610 MW or 18.5 percent. The ELCC method shows that increasing the peak load by 7260 MW returns the system with all of the renewables back to its original daily LOLE value. Therefore the ELCC produces values roughly 10 percent higher (=7260/6610) than the perfect capacity method.

All of these methods are roughly equivalent within the general level of accuracy. Switching from the perfect capacity measure to effective capacity or effective load carrying capability increases the values by 5 to 10 percent. But as seen in Figure 23, the perfect capacity values change by +/- 10 percent when looking at three different shape years. Similar variations were seen for a given shape when varying the penetration levels and the siting scenarios. The important aspect is the relative capacity value of the different types of renewable generation compared to more conventional generation. Thermal generators typically have capacity values in the 90 to 95 percent range. For this system, wind generation has capacity values in the 10 to 15 percent range. Photovoltaic generation is in the 25 to 30 percent range and Concentrating Solar Plants with six hours of storage had values in the 90 to 95 percent range. This relative capacity value is important.

A.6 Capacity Value-Observations from WWSIS

Wind generation is added to a system for its energy value, not its capacity value. Wind generation capacity value is not zero, but tends to fall more in the 10 to 15 percent of nameplate range compared to thermal units that are in the 90 to 95 percent range. These results reflect the fact that the summer-peak load months tend to have lower values of wind generation than the low load spring and fall months. In addition, within the day, wind generation tends to be higher in the middle of the night rather than during the day.

Photovoltaic generation has capacity values in the 25 to 30 percent range. The generation comes, naturally, during the day rather than at night, which gives it a better capacity value than wind. Also, PV tends to do well in the summer peak load months. The only reason for the relatively low value is that the peak loads tend to come later in the day when the solar energy has begun to wane.

Concentrating Solar Plants would normally tend to suffer the same capacity value fate as the PV. However, by their very nature the CSPs lend themselves well to storage. The collector field can be oversized and the collection medium can store the thermal energy without the large collection losses inherent with battery or pumped storage hydro. Because of this, the CSP with six hours of storage was seen to have capacity values in the 90 to 95 percent range that is on par with conventional thermal generation.

Different methods can be used to determine capacity value, including daily LOLE, hourly LOLE and unserved energy. All of the measures tend to produce results within the same range.

A.7 Impact of Transmission: Results from EWITS

Bulk power system reliability is a function of both generation and transmission. Even when the generation fleet is held constant, increasing transmission capacity over broader footprints makes it possible to import capacity from neighboring regions, possibly during system critical times when the LOLP would otherwise be high. New transmission also helps link together loads, wind, and the diversity benefits that accrue to both. For systems that maintain reliability at a given target such as 0.1days/year, the addition of new transmission to tap other generation can avoid or delay the construction of new generating capacity, while holding generation at the same level of adequacy. This relationship has been explored as part of the Eastern Wind Integration and Transmission Study (EWITS), released on Jan 20, 2010.

The EWITS results are better understood within the context of an approach to transmission planning first proposed by the Midwest Independent System Operator.[28]

Figure 24 illustrates the process, which starts from an initial assumption (modified in subsequent steps of the process) of a 20 percent capacity value for wind, based on rated capacity. A rough draft transmission plan is mated with the tentative resource plan, and simulations are done to find the system LOLE. The process iterates, adding or subtracting generation as needed to achieve the LOLE target, and adjusting the transmission plan according to the latest version of the draft resource plan.[29] The process converges when there is a consistent resource and transmission plan that achieves the reliability target.

As part of the EWITS study, a single iteration was performed because of limited time and budget. The wind scenarios contained a range of 224-230 GW of wind capacity that supported a 20 percent annual wind energy penetration, and a 338 GW capacity representing an energy penetration of 30 percent. At these high penetration rates there was considerable geographic dispersion of the wind around the Eastern Interconnection.

[28] Dale Osborn, Midwest Independent System Operator
[29] IVGTF Task 1.6 will examine this issue in more detail.

Figure 24: MISO's Transmission Planning Approach and Generation Adequacy

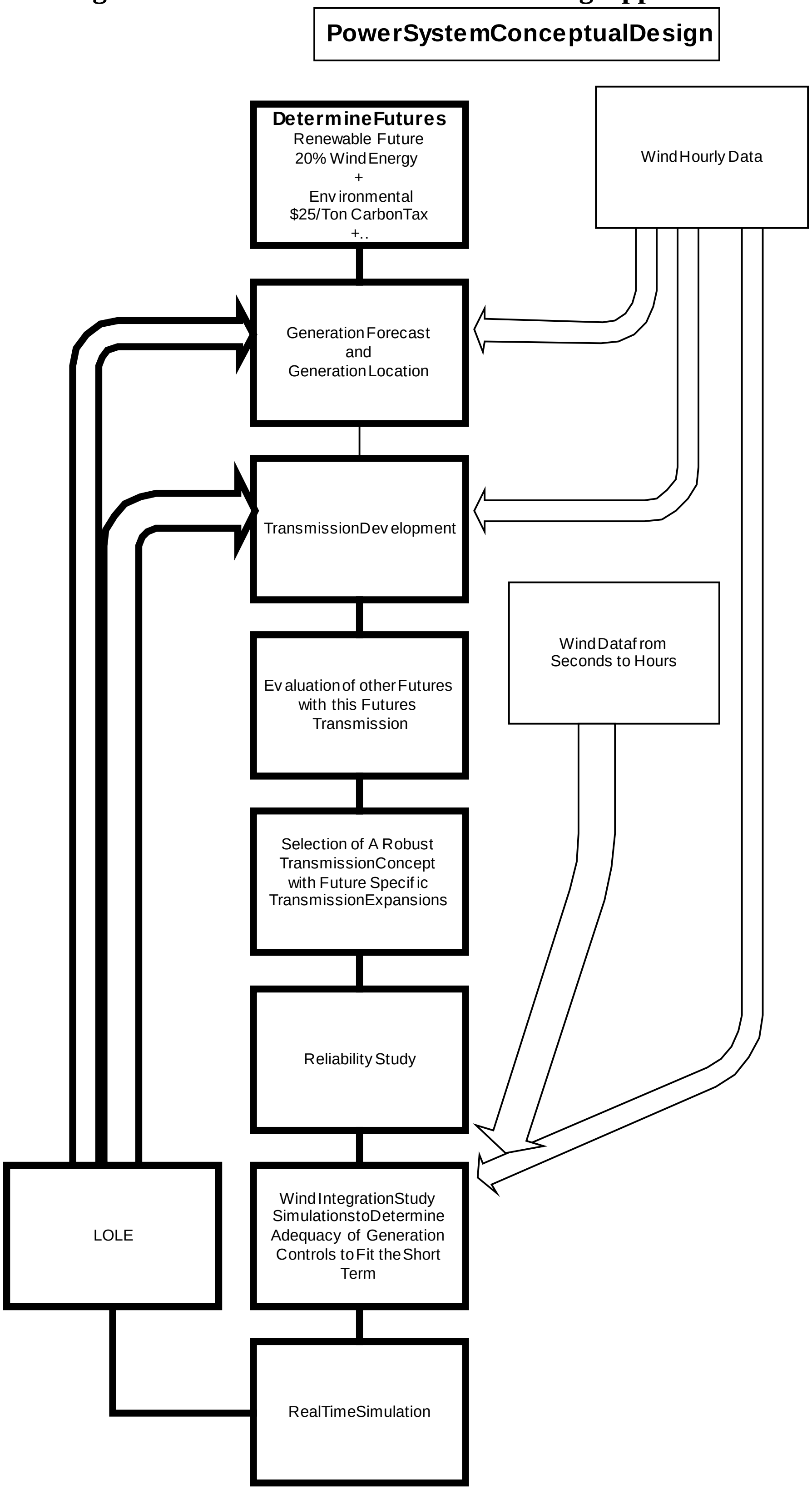


Figure 25 shows the results from the ELCC analysis. Three years of data were used for each of the EWITS scenarios. The scenarios consist of:

1. 20 percent Energy penetration, high capacity factor wind, onshore
2. 20 percent energy penetration, hybrid that moves some of the Midwest wind farther east, with limited off-shore
3. 20 percent energy penetration, local wind with aggressive off-shore
4. 30 percent wind energy penetration, combination of cases 1, 2, and 3

As can be seen from the graph, the capacity values range from 16 percent-31 percent, depending on the scenario. Because the different scenarios represent wind in different locations, one would expect some variation. In particular, the off-shore wind resource is thought to be one of the key drivers of the higher ELCC values that are evident in the last three scenarios. This is because the off-shore wind resources are typically less volatile and more highly correlated with electric demand than on-shore wind resources.

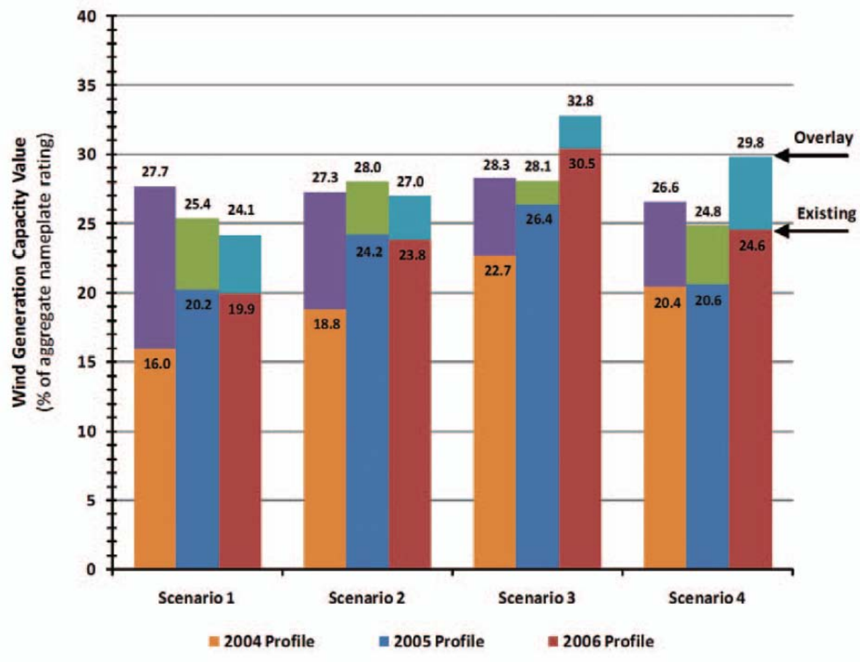
As part of the study, additional transmission was analyzed to support each of the scenarios. Details can be found in the EWITS executive summary[30] but includes significant transmission expansion of 345kV, 500 kV, and 765kV AC, with additional 800kV DC. This large, high-voltage overlay links together large and relatively remote areas and make it possible for enhanced resource sharing and additional relative smoothing of loads, wind, and the net load that must be supplied from conventional generation.[31] Furthermore, this overlay changes the ELCC of wind,

The example shows that reliability can be assessed in small areas or over a broad region. The appropriate footprint would be chosen to reflect the goals of the analysis.

[30] http://www.nrel.gov/docs/fy10osti/47086.pdf

[31] This discussion assumes some form of reserve sharing, energy market, or other institutional mechanism that allows access to the report generation.

Figure 25 EWITS capacity value and impact of transmission



The addition of this new transmission reduces the non-wind generation that is required to meet the 0.1days/year target changes the mix of generation that is available to meet load by broadening the geographic area. The effect is to reduce the LOLE, which in turn reduces the need for additional generation.

A.8 Loss of Load Probability (LOLP)

Loss of load probability is used as the basis of several reliability metrics. These alternative metrics, such as loss of load expectation (LOLE) or loss of load hours (LOLH), are sometimes referred to as "LOLP-based" methods, even though LOLE is a different measure. However, these expected values are derived from the basic probability metrics, and thus are related in this way.

LOLP is calculated by convolving the capacities and forced outage rates of the generation fleet together. This results in the capacity outage probability table (COPT) which shows alternative levels of capacity along with their associated probabilities. Commonly a recursive algorithm is used, but there also exist faster methods that are based on the method of cumulants, which give similar results.

This simple COPT is based on 6 units of 50 MW each. Although it may not be apparent from the table, each line shows the probability of a given MW level of outage along with the probability associated with that level of outage, regardless of which units are out. For example line 2 shows that the probability of 100 MW on outages is 0.06877, which represents the probability that any combination of 2 units are out of service. The cumulative probability of an outage exceeding 100 MW is 0.07729; alternatively, one can interpret this cumulative probability as the LOLP associated with a 200 MW load level.

Table 7. Example capacity outage probability table

Assumes 6-50 MW units, each with FOR=.08			
MW-OUT	MW-In	Probability	LOLP
0 0.0000	300.0000	0.60635500	1.00000000
1 50.0000	250.0000	0.31635913	0.39364500
2 100.0000	200.0000	0.06877372	0.07728587
3 150.0000	150.0000	0.00797377	0.00851214
4 200.0000	100.0000	0.00052003	0.00053838
5 250.0000	50.0000	0.00001809	0.00001835
6 300.0000	0.0000	0.00000026	0.00000026

LOLP is the cumulative probability function

By definition, a probability p is defined on the close unit interval: $0 \leq p \leq 1$.

Using the example, we can see that the LOLP associated with a 200 MW load is 0.07723 and the LOLP of a 150 MW load is 0.008512.

LOLE is an expected value, and is expressed in units that are appropriate to the analysis. It is common to calculate LOLE in terms of days/year, although LOLE can also be calculated in other units such as hours/year (often called LOLH, or loss of load hours).

The general expression for this mathematical expectation can be written as
$E(x) = P_1 X_1 + P_2 X_2 + \ldots P_i \ldots + P_n X_n$

Where $E()$ is the expectation function, P_i and X_i represent the probability and outcome of a given state, and n represents the number of states. This expression is easily adapted to various alternative LOLE calculations:

- Daily LOLE that uses only the probabilities for the daily peak, weekdays would be constructed with 260 associated probabilities and setting each of the X_i terms to *1*. The expected value would therefore be in units of (week) days/year.
- Hourly LOLE, also called LOLH, would use all 8,760 hourly probabilities, setting each of the X_i terms to *1*. (Note: most of the hourly LOLP values will be close to zero, therefore having no discernable impact on the LOLE)

If the load today is 200 MW and the load tomorrow is 150 MW, the LOLE for the 2-day period is then 0.0773 + 0.0085 = 0.0858 days. If this calculation were performed over 260 days the units would be days/year.

As can be seen from these examples, there is no measure of the potential shortfall of capacity, nor is there any estimate of the lost energy that may occur if there should be a loss of load event. Expected unserved energy (EUE) is a related reliability metric that adds a time dimension to the outage calculation so that an estimate can be made of the expected energy loss.

Effective load carrying capability (ELCC) can be calculated using daily LOLE, LOLH, EUE, or other similar reliability metric. The basic principle of ELCC, as illustrated in the main report, is to hold the chosen reliability metric constant with and without the generation in question.

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Abbreviations Used in this Report

Abbreviations	
AESO	Alberta Electric System Operator
BPA	Bonneville Power Administration
CSP	Concentrating Solar Power
DSO	Dispatch Standing Order
ELCC	Effective Load Carrying Capacity
ERCOT	Electric Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
EUE	Expected Unserved Energy
FRCC	Florida Reliability Coordinating Council
ISO	Independent Service Operator
IVGTF	Integration of Variable Generation Task Force
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
MISO	Midwest Independent Transmission System Operator
MRO	Midwest reliability Organization
MW	Mega watt
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council, Inc.
NYISO	New York Independent System Operator
PJM	PJM Interconnection
PV	Photo-voltaic
RC	Reliability Coordinator
RFC	Reliability First Corporation
RMS	Root Mean Squared
RTO	Regional Transmission Organization
SBG	Surplus Baseload Generation
SCADA	Supervisory Control and Data Acquisition
SCED	Security Constrained Economic Dispatch
SERC	SERC Reliability Corporation
SODAR	Sonic Detection and Ranging
SPP	Southwest Power Pool
SPP-RE	SPP Regional Entity
SPS	Special Protection System
TLR	Transmission Loading Relief
TRE	Texas Regional Entity
TSO	Transmission System Operator
VER	Variable energy resource
VRT	Voltage Ride-Through
WECC	Western Electricity Coordinating Council
WIT	Wind Integration Team

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