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December 14, 2015

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
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RE: Docket No. UM 1719 – In the Matter of
PUBLIC UTILITY COMMISSION OF OREGON,
Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity.

Enclosed for electronic filing in the above-captioned docket is Staff Opening Testimony.

/s/ Kay Barnes

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c: UM 1719 Service List (parties)

PUBLIC UTILITY COMMISSION
OF OREGON

UM 1719

OPENING TESTIMONY OF

JOHN CRIDER

In the Matter of
PUBLIC UTILITY COMMISSION OF OREGON,
Investigation to Explore Issues Related to a
Renewable Generator's Contribution to Capacity.

December 14, 2015

CASE: UM 1719
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

December 14, 2015

Q. Please state your name, occupation, and business address.

A. My name is John Crider. My business address is 201 High Street SE Suite 100, Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's observations and recommendations regarding the calculation methods for estimating a renewable generator's capacity credit.

Q. Did you prepare exhibits for this docket?

A. Yes. I prepared the following seven Exhibits:

1. Exhibit Staff/101, Staff Qualifications, consisting of 1 page;
2. Exhibit Staff/102, "Methods to Model and Calculate Capacity Contributions of Variable Generation," Michael Milligan (National Renewable Energy Laboratory); consisting of 63 pages;
3. Exhibit Staff/103, presentation from Michael Milligan to Oregon PUC, dated August 17, 2015, consisting of 31 pages;
4. Exhibit Staff/104, "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes," Andrew Mills (Lawrence Berkeley National Laboratory), consisting of 10 pages;
5. Exhibit Staff/105, presentation from Andrew Mills to Oregon PUC, dated August 17, 2015, consisting of 40 pages;

6. Exhibit Staff/106, "Effective Energy and Capacity Contributions of Wind Resources," John Fazio (Northwest Power and Conservation Council), consisting of 9 pages; and
7. Exhibit Staff/107, presentation from John Fazio to Oregon PUC, dated August 17, 2015, consisting of 24 pages.

Q. Please describe the primary concern of this docket.

A. It is generally recognized that all electric generators provide two commodities to the power grid – namely energy and capacity. A generator's ability to provide energy to the grid is easily quantified since it can be directly metered. Capacity is more difficult to quantify since it represents a future potential energy which is not directly measurable. Capacity must always be estimated. Methods for estimating and quantifying capacity for traditional thermal generation plants are well established and their accuracy is understood. Such is not necessarily the case with renewable generators. Their "fuel source" – wind, water, or sun – is not always predictably available when capacity is needed by the power grid. This fact creates a challenge in quantifying capacity for renewable generators. The primary concern of this docket is to investigate methodologies for estimating a renewable generator's capacity contribution to the system and to inform the Commission's policy-making in this area moving forward.

Q. What specific issues are included for investigation in this docket?

A. The Staff report which resulted in the adoption of this docket identified three issues for investigation: 1) a comparison of methods and determination if a standardized method should be agreed upon; 2) identification of the relative risks and benefits of the approaches; and 3) a determination of how often the capacity credit should be re-evaluated.[1]

Q. Please describe the materials on which this testimony is based upon.

A. On August 17, 2015, the Commission held a workshop in this docket at which parties received three presentations. This testimony draws on materials directly from these presentations and from the scholarly papers that form the foundation for them.[2] These materials are included as Exhibits to this testimony.

Q. Does Staff draw any general conclusions from reviewing the materials?

A. Yes. It seems clear from the presentations and the supporting reports that there is strong consensus among the experts that offered presentations that the "effective load carrying capability" (ELCC) method is the preferred method for calculating renewable generator capacity.[3,4,5] More generally, it is accepted by the experts that any methodology that is based in some way on a metric that measures or predicts the "loss of load probability" (LOLP) is a recommended

[1] Staff report dated February 9, 2015, presented at the regular OPUC Public Meeting, March 10, 2015, agenda item 1.
[2] Presentations from the August 17, 2015, workshop include: 1) "Methods to Model and Calculate Capacity Contributions of Variable Generation," Michael Milligan (National Renewable Energy Laboratory); 2) "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes," Andrew Mills (Lawrence Berkeley National Laboratory); 3) "Effective Energy and Capacity Contributions of Wind Resources," John Fazio (Northwest Power and Conservation Council).
[3] Mills presentation, slide 10.
[4] Fazio presentation, slides 5-8, generally.
[5] Milligan presentation, slide 4.

practice. ELCC is the North American Electric Reliability Corporation (NERC) preferred loss-of-load-based method.[6]

Q. Please explain what ELCC measures.

A. The ELCC of a generator is defined as the amount by which the system's loads can increase (when the generator is added to the system) while maintaining the same system reliability as measured by the LOLP.[7]

Q. Please provide an example of this measurement.

A. Assume the electric system at present has a probabilistic chance that it will fail to meet its load equal to one day in a ten-year period; that is, there is one instance in ten years where the system simply cannot meet load. Assume that a new generator is added to the system which brings some level of incremental capacity to the system. That incremental capacity can be called the "capacity credit" of the generator. The incremental capacity has the effect of lowering this probability of not meeting the load. In this example, assume that the new probability (LOLP) becomes one day in 11 years instead of one day in ten years. The ELCC method would have us then add additional load to the system and measure the new LOLP. As new load is added, the LOLP will increase. The precise capacity addition that makes the LOLP once again reach a value of one day in 10 years is deemed the capacity credit for that generator.

Q. What are the other methods for estimating the capacity credit for a generator?

[6] Ibid.
7 Amelin, M. "Comparison of Capacity Credit Calculation Methods for Conventional Power Plants and Wind Power." IEEE Trans. Power Syst. (24:2), May 2009.

A. The most used alternatives to ELCC fall into two categories – those based on ELCC approximations and those based on historical generation levels. The "historical" approaches are based on measuring the output of the generator during a set of potential peak hours, and then dividing that number by the maximum possible output from the generator during that same time period. In essence, this a measure of capacity factor over a specified time frame.[8] Estimates of capacity that are based on this type of calculation are generally referred to as "time period analysis" (TPA)[9] or time period methods.

Q. Please discuss the TPA methods.

A. TPA measures or estimates the generation output of the renewable generator during likely system peak hours only.[10,11] A typical TPA will involve isolating the 100 or so hours in the year when the peak load is expected to occur (based on historical data) and counting the total historical generation from the renewable generator during this time period in previous years. The ratio of the realized generation to the potential nameplate generation yields the capacity credit estimate.

Q. What is the shortcoming of TPA?

A. TPA relies on a primary assumption that the loss of load probability corresponds exactly with the peak load; in other words, it is assumed that if

[8] Mills presentation, slides10 – 13.
[9] Milligan presentation, slide 13.
[10] Milligan presentation, slide 13.
[11] Mills presentation, slide 10.

reliability is achieved during the likely peak hours, then reliability is assured for the entire year.

Q. What is the error in this assumption?

A. The assumption disregards that there may be a significant non-zero LOLP event at times other than the peak days of the year. As one example, utilities often schedule plant maintenance outages in the fall. If there is an unpredicted hot spell in the fall while a major plant is in outage and load increases dramatically, the utility might find itself unable to meet the load and experience a reliability event outside the peak.

Q. Would the ELCC method capture these non-peak events?

A. Yes. The primary difference between the ELCC and TPA methods is that the full ELCC method is a measure of capacity in all hours of the year, not just during the peak.

Q. Does TPA have additional shortcomings?

A. Yes. Since the methodology measures capacity only at the peak hours, the results become highly dependent on the period of time chosen in the analysis. In other words, the amount of capacity credit determined becomes dependent on the actual hours analyzed. The fact that the hours analyzed may be chosen somewhat arbitrarily implies that the resultant output also carries a level of arbitrariness. If the capacity credit is used as an element in ratemaking, this level of arbitrariness may not be acceptable. Good ratemaking demands more consistency in outputs. In addition, TPA does not typically utilize synchronized load and generation data but relies on averages thus yielding a less precise value for capacity.

Q. What is Staff's conclusion regarding TPA?

A. TPA represents a simplified and "back of the envelope" estimation for capacity credit. TPA has the advantage of being relatively straightforward to calculate with a spreadsheet and proper data, and does not require an iterative process thus takes less time to complete. In the past, these were important considerations in light of computational restrictions. However, at present it appears that both proper ELCC methodology and approximations to ELCC are well within the technological capabilities of the utilities. Since these reliability-based ELCC approaches are recognized as the best practice by the experts and both Portland General Electric (PGE) and PacifiCorp have demonstrated an ability to use ELCC,[12,13] Staff sees no reason for relying on TPA methods for capacity estimates.

Q. Is there a potential limitation associated with the ELCC method?

A. Yes. In order for the calculation to be valid, an input set of data must be available which consists of renewable generation data that is time-synchronized with load data. It is not valid to use data that is averaged over long periods, or to use load data that comes from a different year than the

[12] PGE 2016 Integrated Resource Plan workshop presentation, August 29, 2013, slide 58.
[13] PacifiCorp Integrated Resource Plan 2013, Appendix O.

generation data. Valid results require a sophisticated set of synchronized data.[14]

Q. Is it possible to apply the ELCC method for a subset of hours instead of an entire year (8760 hours)?

A. Yes. The ELCC methodology can be applied to any time period. An annual approach will estimate capacity credit over the course of an entire year ("full ELCC analysis"). A peak-only method ("peak ELCC analysis") would use the LOLP-based methodology but apply it only to the hours when a system peak is likely to occur. However, synchronized load and generation data is still required.

Q. What is the effect of applying the ELCC method to only the peak hours?

A. The question answered by application of the ELCC method is – what is the most likely level of capacity credit that the generator (or class of generators) will provide over the analyzed time period? Therefore, if only the peak hours are analyzed, the ELCC method answers the question "what is the most likely level of capacity delivered to the system during the peak hours?"

Q. Why would one use the peak ELCC method in place of the full ELCC method?

A. Traditionally in utility planning, capacity credit has been measured and compensated for during peak hours only. A calculation of capacity credit using the full ELCC (i.e., 8760 hours annually) provides the level of capacity the

[14] Milligan presentation, slide 15.

generator provides at all times during the year. If the Commission's policy choice is instead to provide compensation only for peak hours, it is computationally straightforward to apply the ELCC method only to the peak hours.

Q. Please provide an illustrative example of the difference between the two ELCC approaches.

A. PGE is a winter peaking utility. If PGE applies the ELCC method across all hours of the year to a solar plant, it will estimate the amount of capacity the solar generator contributes throughout the year. More capacity is offered by the solar generator during the summer months than during the winter months because of the prolonged hours of sun in the summer. PGE performed a similar analysis and reported the results at its August 13, 2015, IRP public meeting. The preliminary results showed that solar was estimated as having a winter ELCC of 10 percent but a summer ELCC of 55 percent.[15]

Q. What is the interpretation of these results?

A. The immediate conclusion is that solar provides five times as much capacity credit in the summer as in the winter, which means that on average a solar plant is five times more likely to be available to generate when needed during the summer than it is in the winter.

Q. What is the significance of these results?

[15] See https://www.portlandgeneral.com/our_company/energy_strategy/resource_planning/docs/2015-08-13-public-meeting-3.pdf

A. The significant aspect of these results is that the resulting value of capacity credit from the application of the ELCC method is highly dependent on the time frame analyzed. Applying the ELCC method to only peak-hours will yield an estimate of capacity credit for capacity delivered during peak only. Applying the ELCC method to all hours of the year will capture all potential capacity delivered to the system, independent of when the peak is. This distinction may be of importance in forming the Commission's policy on creating rates used to compensate generators for capacity.

Q. Which ELCC approach is "more correct"?

A. The fact that the methodology yields different answers depending on the time frame analyzed is an important point. Neither of the approaches to calculating ELCC is "more correct" but they reflect different system attributes. Calculating ELCC over the entire year ("full ELCC analysis") will capture all deliveries of capacity to the system, regardless of whether that capacity was delivered at system peak or at another time. Calculating ELCC over peak hours ("peak ELCC analysis") will capture only that capacity that is delivered during the peak load hours of the year.

Q. Why is the choice of ELCC method important?

A. Staff is concerned about the estimation of capacity credit because this credit may be used as a basis for capacity compensation for generators. As explained in this testimony, the full ELCC and peak ELCC methods estimate different commodities delivered to the system. The full ELCC method estimates the amount of capacity the generator delivers to the system over the entire year, while the peak ELCC method delivers the answer to the more traditional planning question of how much capacity the generator is expected to deliver during likely peak hours.

Q. Please discuss approximations to ELCC.

A. There are three approximation methods widely used[16] – the "Capacity Factor" technique, the Garver approximation, and the Z method. The Capacity Factor technique is similar to the TPA in that it uses a capacity factor, but it is an improvement since capacity value is weighted by LOLP. The result is that more capacity credit is given during hours where the LOLP is highest. The Garver approximation uses a mathematical function to estimate the capacity credit. The Z method is a statistical approach which treats the difference between generating capacity and load as a stochastic variable and estimates the capacity credit using statistical means.

Q. How accurate are these methods compared to ELCC?

A. According to a comparison study conducted by the National Renewable Energy Laboratory (NREL), the Capacity Factor method produced results most closely matching ELCC, with a 4.12 percent error. The best Garver approximation had an 11.9 percent error and the Z method was the worst performer of the three with a 13.5 percent error.[17]

Q. How is the ELCC method applied to generators?

[16] "Comparison of Capacity Value Methods for Photovoltaics in the Western United States", S. Madaeni, R. Sioshansi and P. Denholm (NREL), Technical Report NREL/TP-6A20-54704, July 2012.
[17] Id. p. 21

A. The ELCC method can be applied to a single individual generator in which case the result is the estimated capacity credit of that particular generator. Each generator will produce a unique value of capacity credit based on its particular electrical characteristics, location, proximity to other generators and other factors. Obviously, applying the method on an individual basis to each generator would create an extremely time-intensive analysis. The simplifying assumption is typically made that all resources of a particular technology type will have similar capacity credits. Thus, generators that are alike are aggregated and the ELCC method is applied to the class of generation. Classes are grouped by technology and perhaps some modifying characteristics – renewables would be grouped by fuel (hydro, wind, solar) and further grouping might separate, say, solar plants with sun-tracking capability from simpler fixed-tilt solar plants.

Q. What is Staff's recommendation regarding how the ELCC should be calculated for different generating technologies?

A. Staff believes it is reasonable and consistent to use the same technology groupings as defined for the Oregon Renewable Portfolio Standard (RPS). The RPS defines four general classes of renewable energy generators as follows: 1) Wind energy; 2) Solar photovoltaic and solar thermal energy; 3) Wave, tidal and ocean thermal energy; and 4) Geothermal energy.[18]

[18] See ORS 469A.025(1)

Q. Do the commission's rulings on PURPA[19] qualified facilities (QF) compensation inform the ELCC discussion?

A. Yes. It is clear from the Commission's body of decisions in the QF area that an independent renewable generator is compensated for capacity delivered to the system only when the utility is in need of that capacity; or more precisely, the avoided cost rate for capacity paid to the contracted power producer is nonzero only during times of resource deficiency and is zero otherwise.[20] Thus, for ratemaking purposes, it appears reasonable to compensate the independent renewable generators for capacity only whenever the system is short of resources. Traditionally this delineation between resource adequacy and resource need has been analyzed on a monthly or seasonal block basis using average capacity and loads, and utilizing the logical assumption that if the system had adequate resources to serve peak load, then all other load demands would also be met as a natural consequence. Although this rule-of-thumb often holds true, the application of the ELCC method allows a more precise discovery of *all* hours when the LOLP is non-zero, regardless of when the system peak occurs. It should be clear that any hour that has a nonzero LOLP is a direct indication that a *de facto* resource deficiency exists during that hour. That is, a nonzero LOLP can only exist if there are not enough resources to meet load in that hour. Therefore, application of the full ELCC method essentially discovers all hours of potential resource deficiency in the system

[19] Public Utilities Regulatory Policy Act of 1978, 42 USC Chapter 134.
[20] See generally Commission Order No. 14-058

during an entire year. Since the Commission has expressed its choice in the PURPA dockets to compensate independent renewable generators for capacity delivered in periods of resource deficiency, it logically follows that the Commission would support a compensation policy based on the ELCC method. This is true because the ELCC method directly discovers hours of system deficiencies, or hours when the system resources are not adequate to meet load.

Q. What conclusions does Staff draw from the preceding discussion?

A. First, there is a consensus among the workshop presenters that the ELCC methodology, based firmly on measurable loss-of-load metrics, is the preferred method for estimating capacity credit for generators. Second, the ELCC methodology is flexible enough to be applied to either all hours of the year to calculate an annual capacity credit, or applied to peak hours only to provide a measure of peak capacity credit, depending on Commission policy. Finally, since the estimate of capacity credit will change in relation to other system variables related to planning (loads, outage schedules, resource acquisitions and retirements, etc.), Staff believes it is reasonable to update the capacity credit on the same two-year IRP schedule as these other inputs.

Q. Should the utilities be free to choose a method to calculate capacity?

A. No. If the capacity credit will be used for ratemaking purposes in any instance, then independent renewable generators must be treated fairly. With no prescribed method for establishing the capacity credit, utilities would be free to choose a method which may disadvantage these third party generators. This situation could create unjust disparity between generators on the same utility system, and also between utilities. A uniform methodology among all regulated utilities will guard against any potential unfair treatment.

Q. Are there any instances where a utility may not be able to perform a full ELCC analysis?

A. Yes. The ELCC methodology requires synchronized load and generation data from the renewable generators. There may be instances when this data is unavailable.

Q. How should the utility proceed when a full ELCC analysis is impossible?

A. Staff recommends that the Commission allow waiver of the full ELCC requirement on a case-by-case basis. It is incumbent upon the utility to provide evidence in support of the waiver to the satisfaction of the Commission. If an ELCC analysis is impossible, then the preferred approximation is the "Capacity Factor Approximation" as it has been shown to provide results that most closely match the output of ELCC analysis[21].

Q. Please summarize Staff's position.

A. Staff's position can be summarized as follows: 1) There are two general approaches to determining a renewable generator's capacity credit – the ELCC method and variations on the Time Period Analysis; 2) Of these two approaches, expert consensus is that ELCC is the preferred approach and Staff supports this conclusion; 3) ELCC analysis can be performed over all the

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hours of the year (full ELCC), or a subset of hours (peak ELCC). Staff supports a full ELCC implementation since a full ELCC will account for all hours of system resource inadequacy, not just those instances that occur at peak. Capacity delivered at any time it is needed (not just at peak) reflects a nonzero avoided cost to the utility that should be captured; and 4) the Commission should consider conditions where an approximation to the full ELCC is an acceptable substitute and allow limited waivers.

Q. What is Staff's recommendation?

A. Staff recommends the following: 1) the Commission direct all electric utilities to use the full ELCC methodology for estimating the capacity credit for each class of renewable generation; 2) the "classes" of renewable generation should be based on the classification of renewable resources found in ORS 489A.025(1)[22]; 3) the capacity credit for each class of generator should be updated in each IRP and each IRP update, 4) the Commission should allow the use of an approximation in place of the full ELCC in cases where synchronized load and generation data is not available or where the utility can a demonstrate a full ELCC analysis is otherwise not possible.

Q. Does this conclude your testimony?

A. Yes.

[22] ORS 469A.025 (1) defines energy types used to comply with the RPS and includes four classes: (a) Wind energy, (b) Solar photovoltaic and solar thermal energy, (c) Wave, tidal, and ocean thermal energy, and (d) Geothermal energy.

CASE: UM 1719
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

December 14, 2015

WITNESS QUALIFICATIONS STATEMENT

NAME: John Crider

EMPLOYER: Public Utility Commission Of Oregon

TITLE: Senior Utility Analyst
Energy Resources And Planning Division

ADDRESS: 201 High Street, SE., Suite 100
Salem OR 97301-3612

EDUCATION: Bachelor Of Science, Engineering,
University Of Maryland

EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since August of 2012. My current responsibilities include analysis and technical support for electric power cost recovery proceedings, with an emphasis on variable power costs and purchases from qualifying facilities. Prior to working for the OPUC I was an engineer in the Strategic Planning division for Gainesville Regional Utilities (GRU) in Gainesville, Florida. My responsibilities at GRU included analysis, design and support for generation economic dispatch modeling, wholesale power transactions, net metering, integrated resource planning, distributed solar generation and fuel (coal and natural gas) planning. Previous to working for GRU, I was a staff design engineer for Eugene Water & Electric Board (EWEB) where my responsibilities included design of control and communications system in support of water and hydro operations.

I am a registered professional engineer in both Oregon and Florida.

CASE: UM 1719
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 102

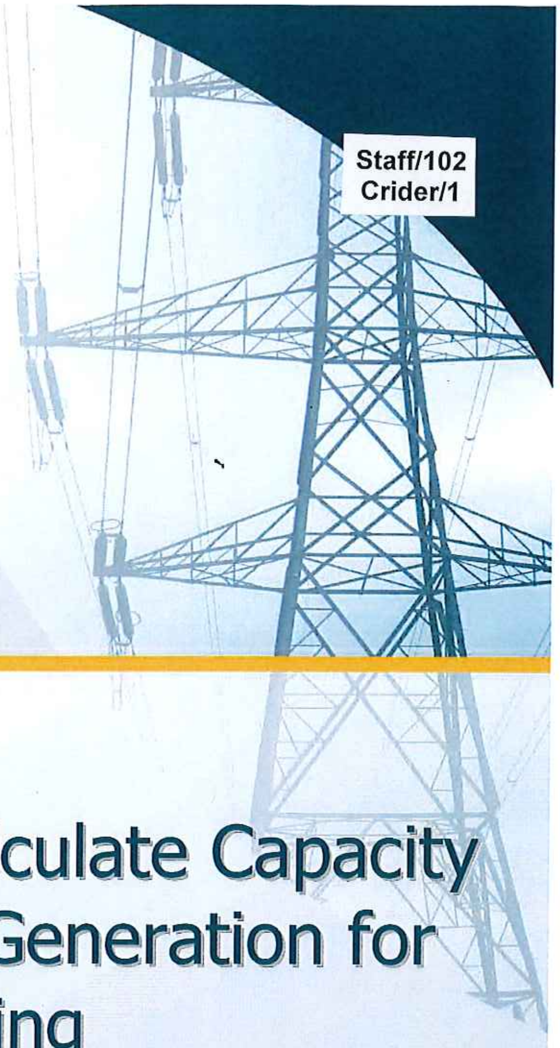
Exhibits in Support
Of Opening Testimony

December 14, 2015

Staff/102
Crider/1

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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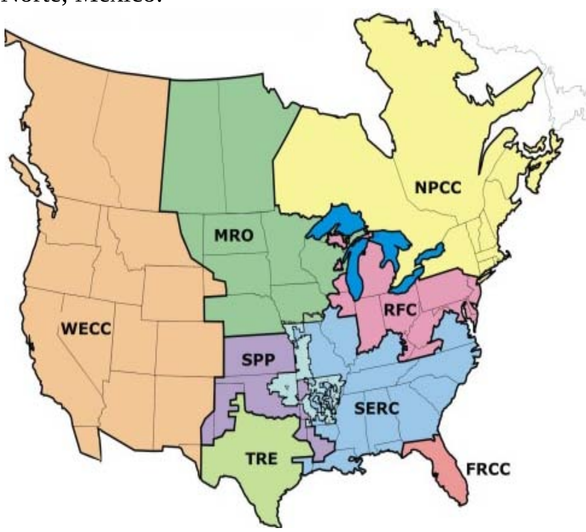
NERC's Mission

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.

Table of Contents

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

Staff/102
Crider/6

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.

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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.

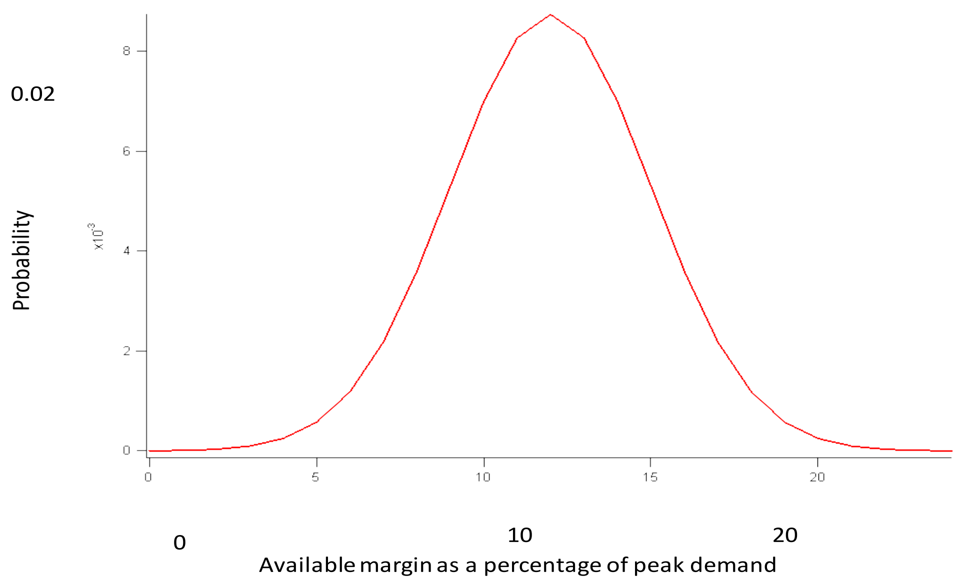
[11] D. Hawkins, B. Kirby, Y. Makarov, M. Milligan, K. Jackson, H. Shiu (2004) RPS Integration Costs Phase I Analysis Results Workshop • 20 February 2004, California Energy Commission. Sacramento, CA.

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.

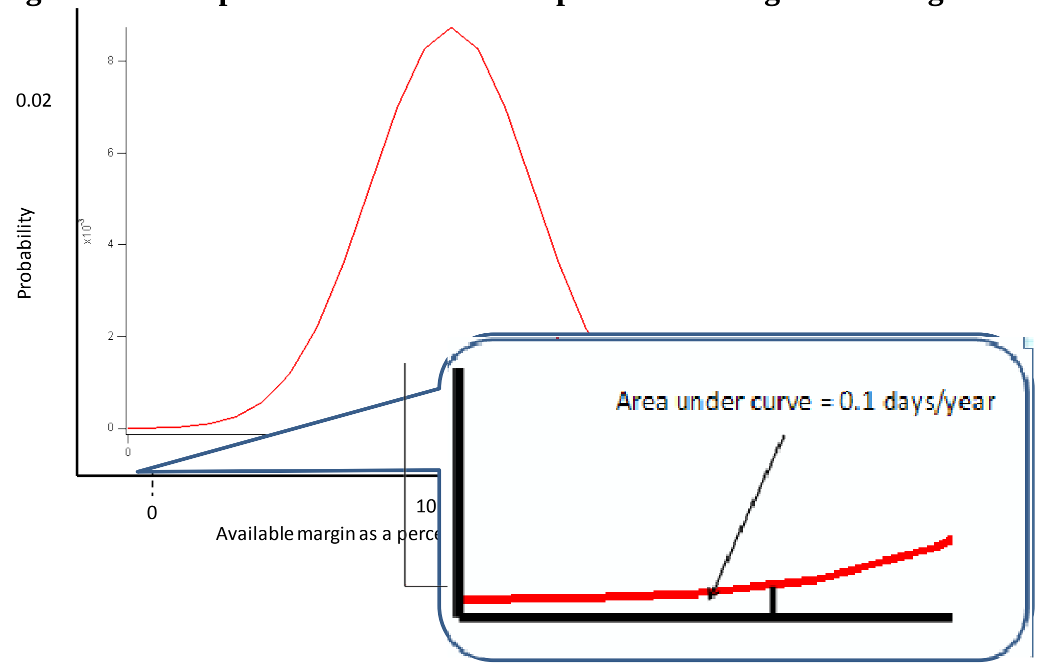
Figure 1 illustrates the concept of LOLP, which is used in the calculation of LOLE. For most of the year, there is sufficient reserve margin, but during some days (or hours) there is a non-zero probability that multiple generation failures may result in insufficient reserves and possibly load shedding. 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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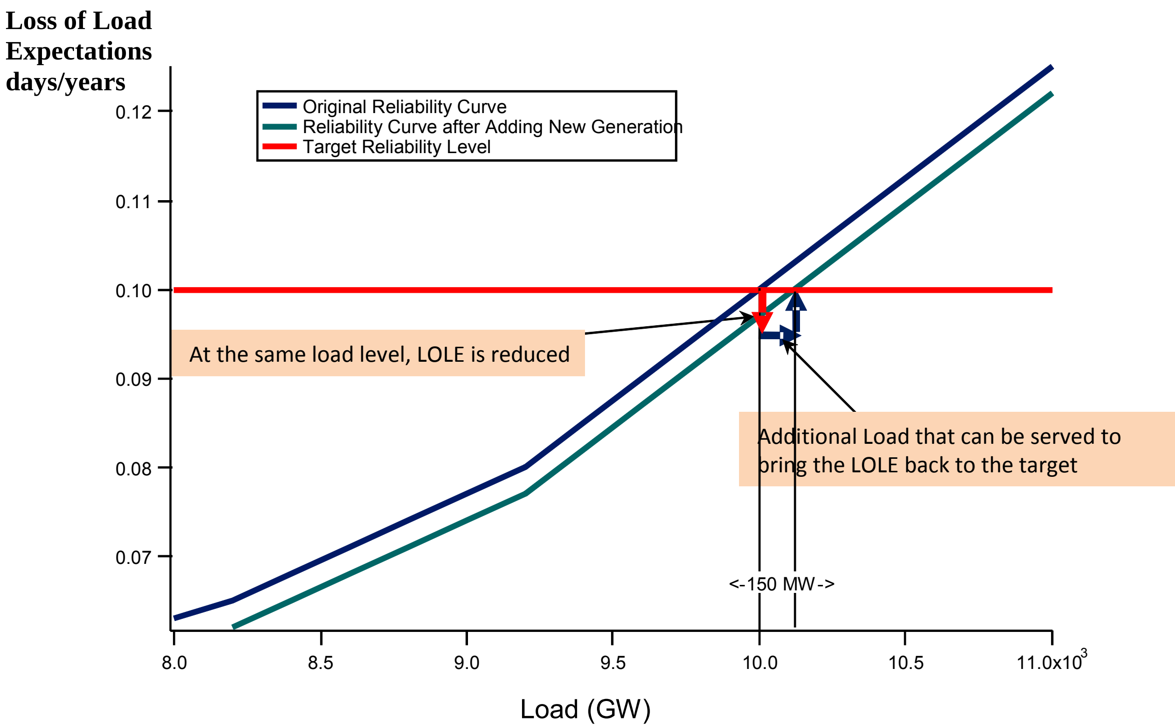
Figure 3: Example of reliability curves when a new generator is added to the resource mix



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]

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[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:

$U = (1 – F) C$

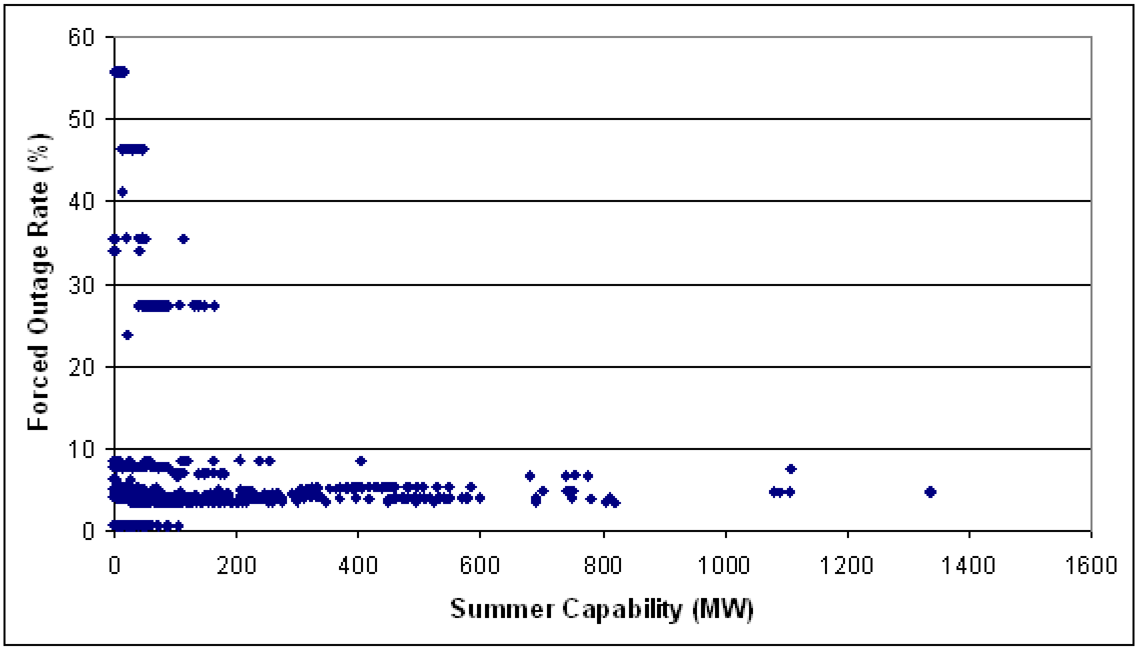
Where:

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.

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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

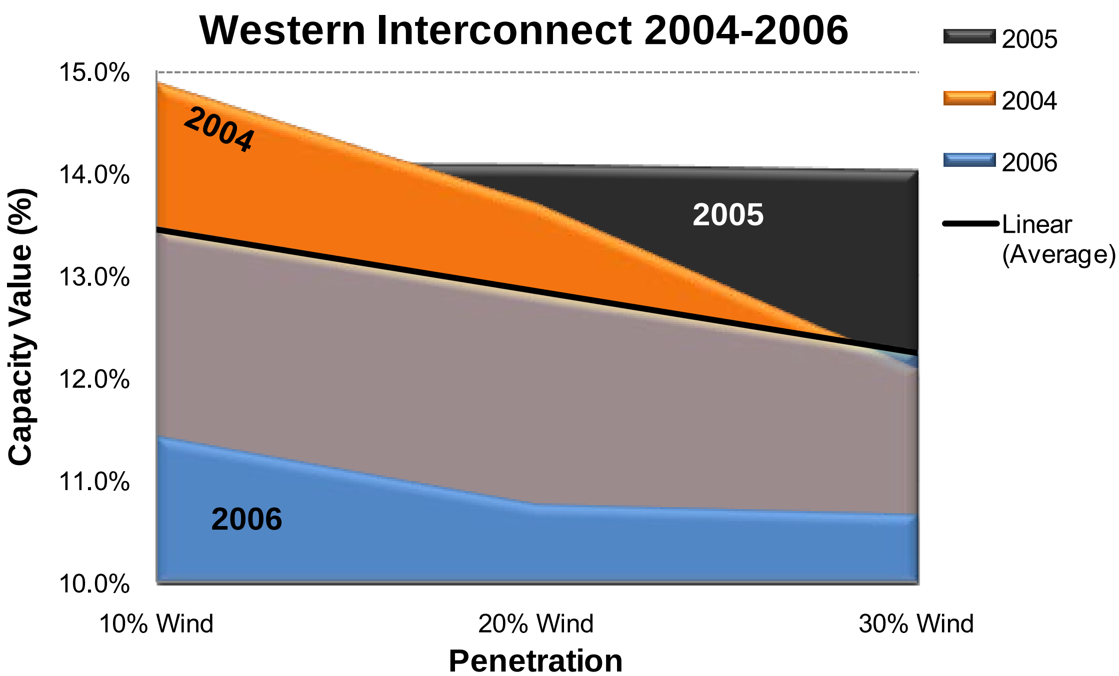
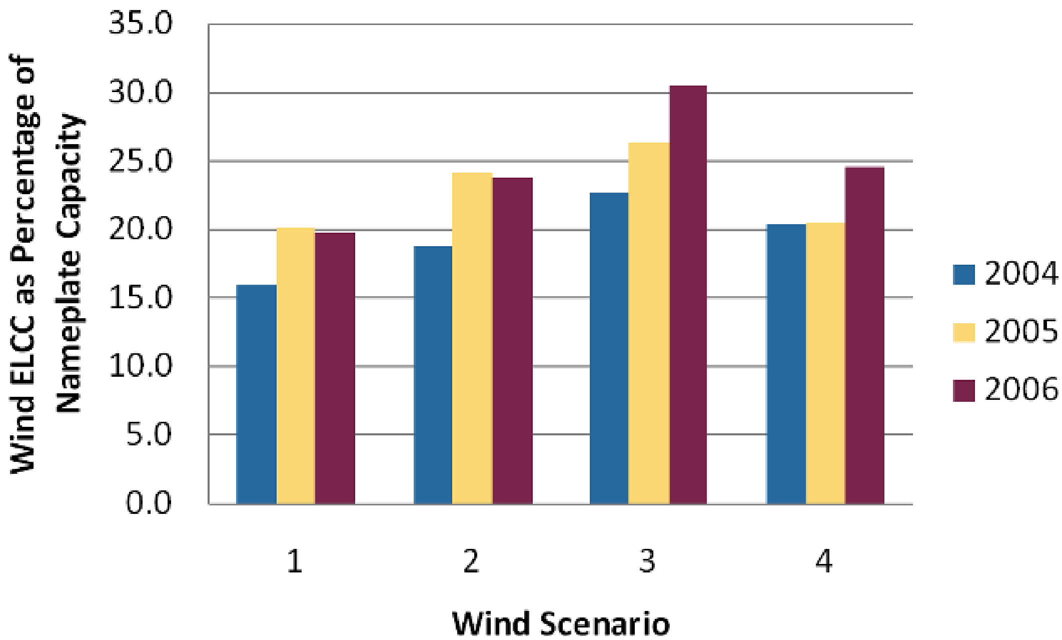


Figure 6 is from the Eastern Wind Integration and Transmission Study, covering most of the Eastern Interconnection (US). Using time synchronized wind and load from the same 3-year period as the Western study, 2004-2006 this study found somewhat more variation from year to year. The scenarios represent 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.

[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

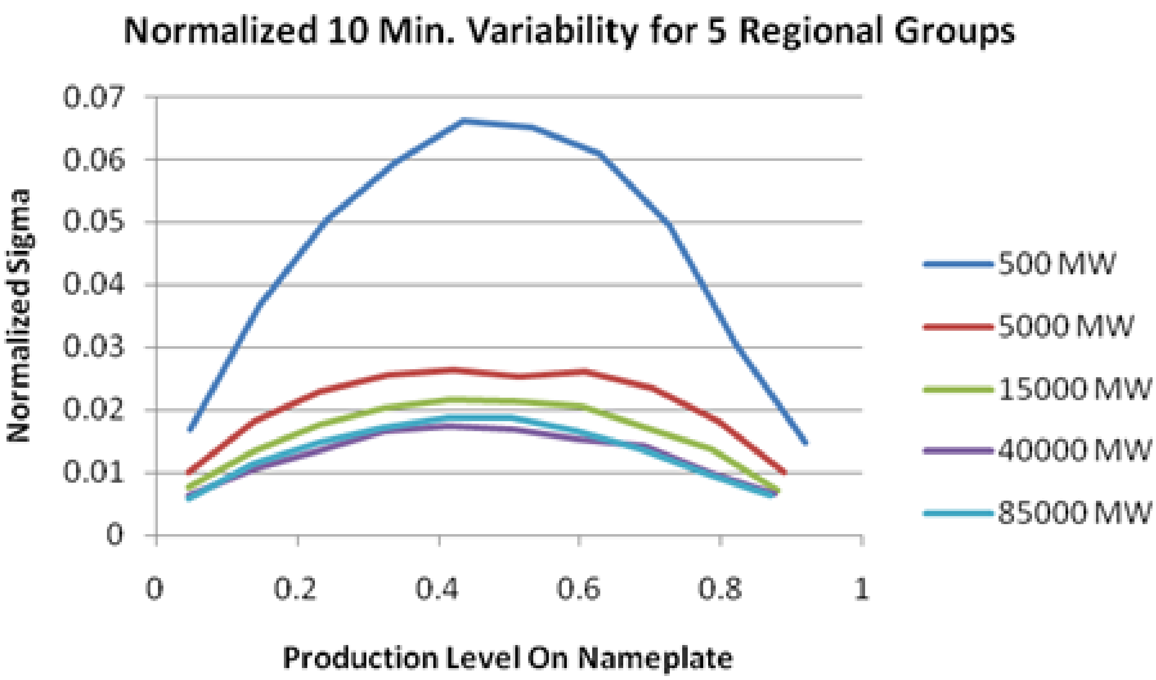
[19] Hasche, B.; Keane, A.; O'Malley, M., *Capacity Value of Wind Power: Calculation and Data Requirements.* IEEE Transactions on Power System. In Press.

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

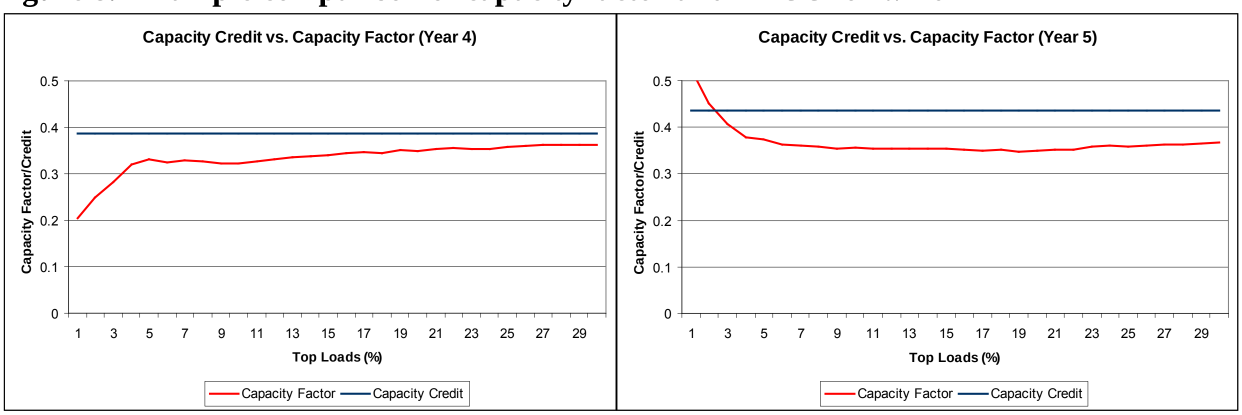
Other methods focus on the variable generation level during system-critical periods. These periods are defined differently, based on the system in question. Perhaps one of the first approaches was developed by PJM, although there are other similar approaches used by ISO New England, the NYISO, MAPP, 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.*

[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.*

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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.

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Figure 9: Study Area Risk versus Capacity Additions

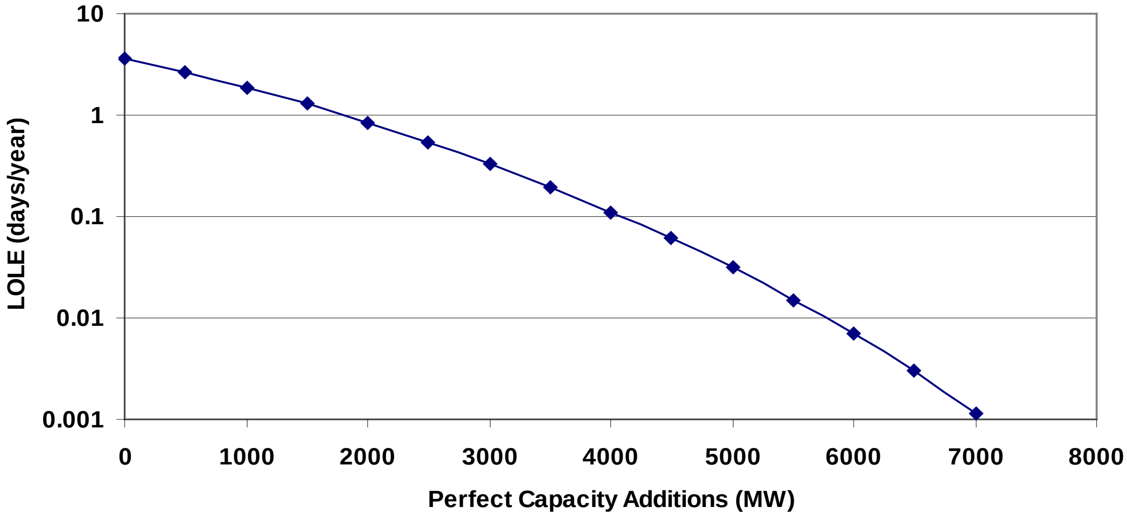


Figure 10: Study Area Risk with Renewable Additions

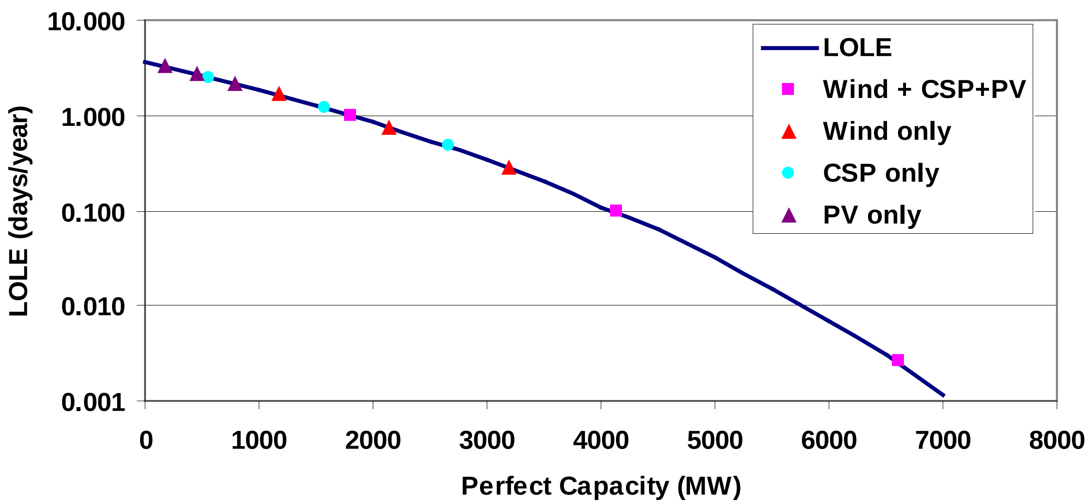


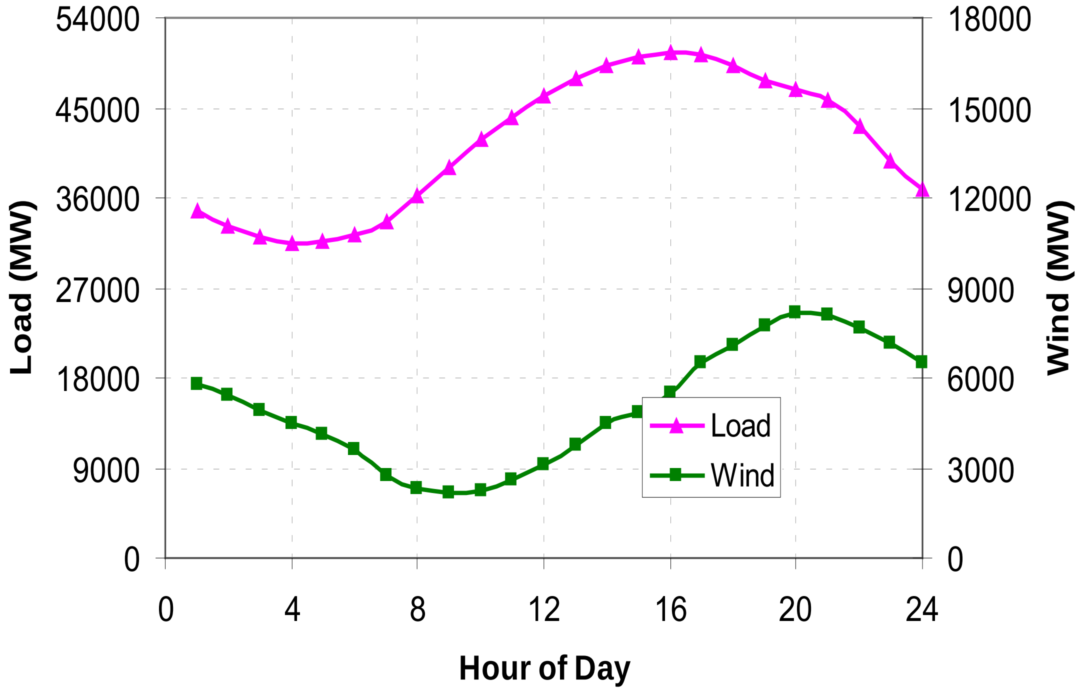
Table 1 shows the nameplate capacity of the wind, CSP and PV generation added in the three levels of penetration. Table 2 shows how the capacity values derived from Figure 10 compare to their nameplate ratings on a percentage basis. It is clear that there is significant variation in capacity value among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



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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

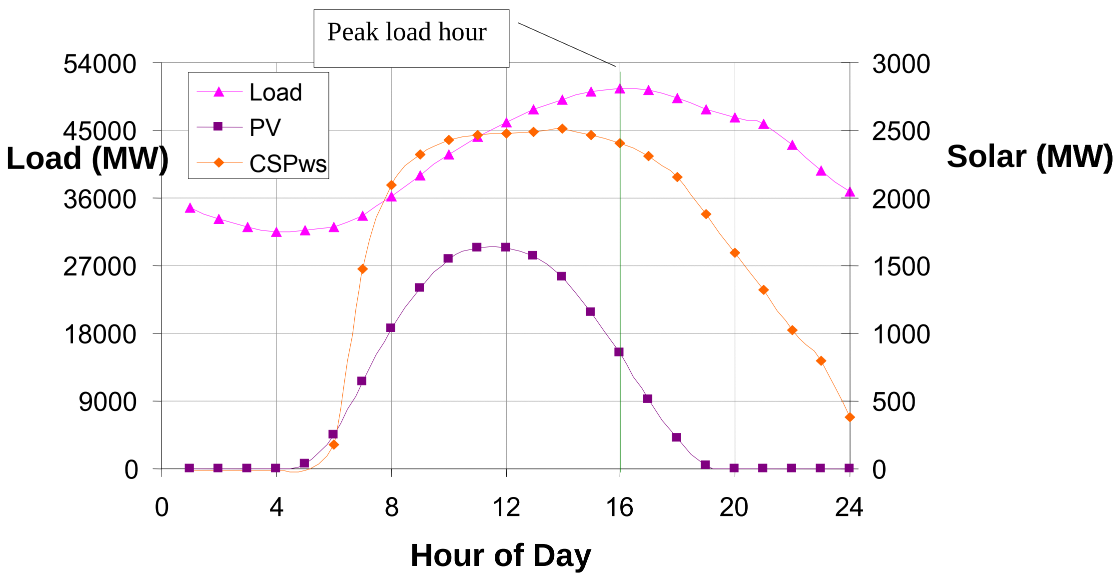
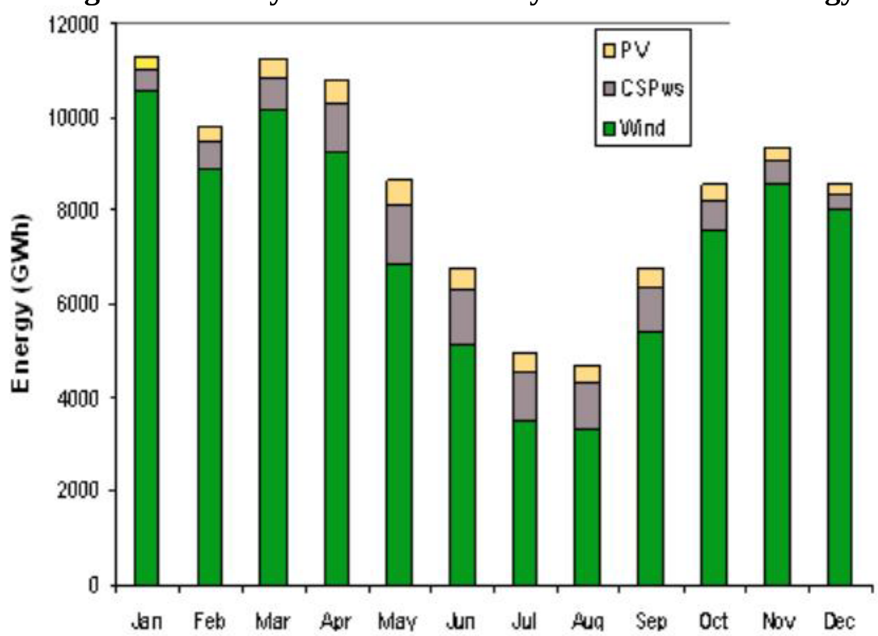


Figure 13: Study area total monthly wind and solar energy



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

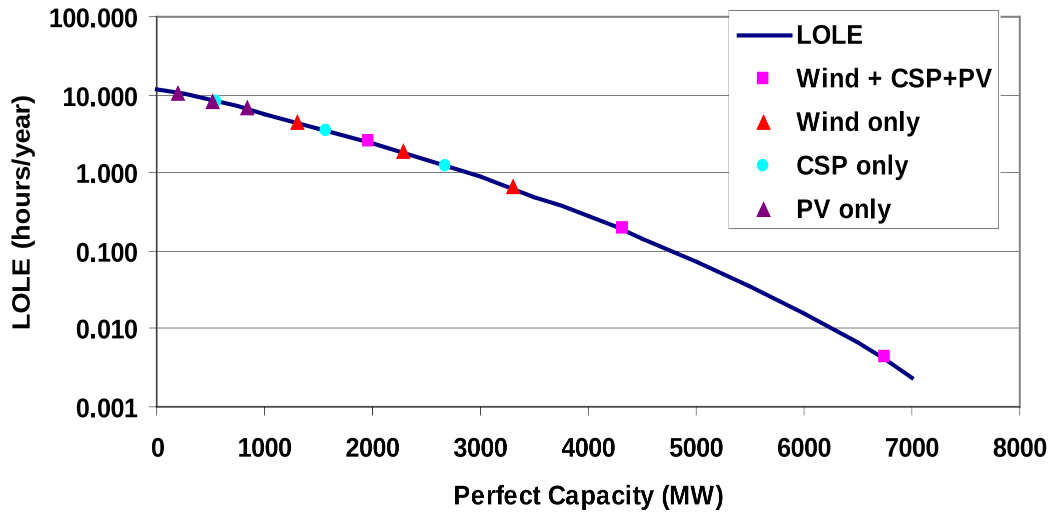


Figure 15: Study area risk in unserved energy

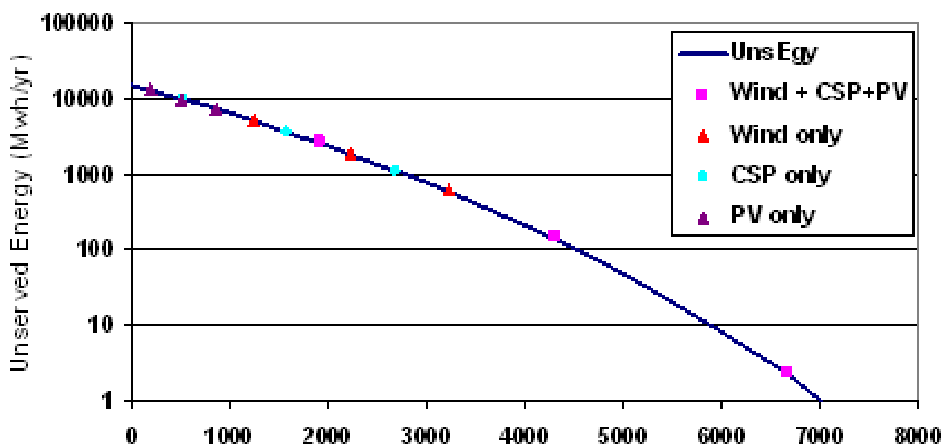


Table 3 Renewable capacity values by type, 2006 shapes, perfect capacity, hourly LOLE				
Penetration	Wind + CSP + PV	Wind only	CSP only	PV only
10% wind, 1% solar	17.1%	12.6%	90.8%	32.1%
20% wind, 3% solar	18.5%	11.5%	92.7%	30.3%
30% wind, 5% solar	18.9%	11.0%	92.6%	29.0%

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.

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

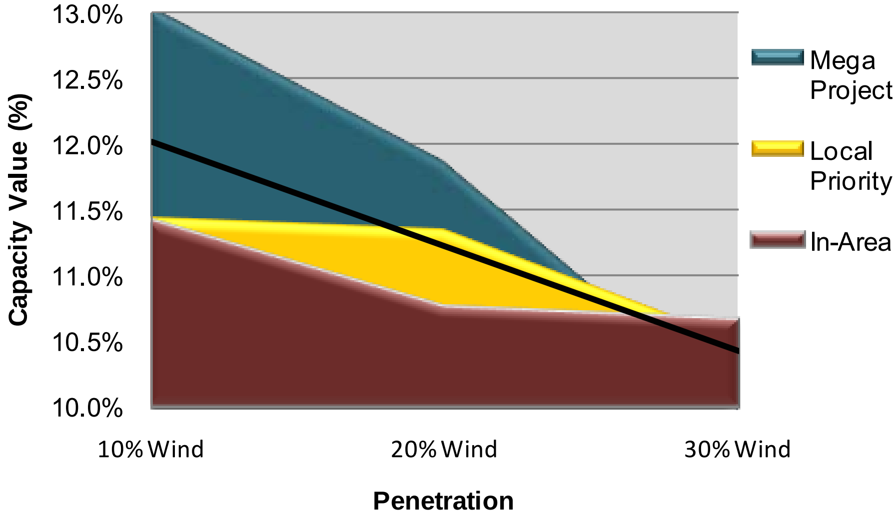

Figure 17: CSP with storage capacity values by scenario, 2006 shapes, perfect capacity

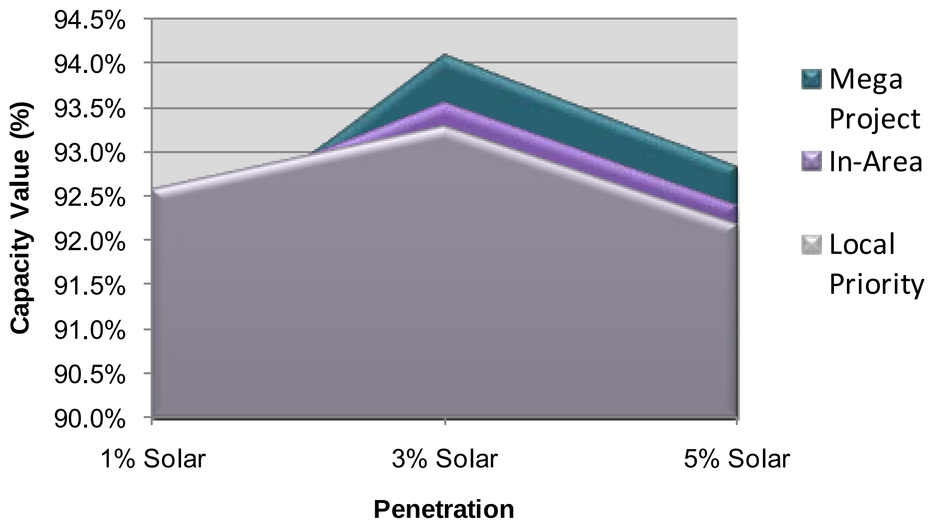

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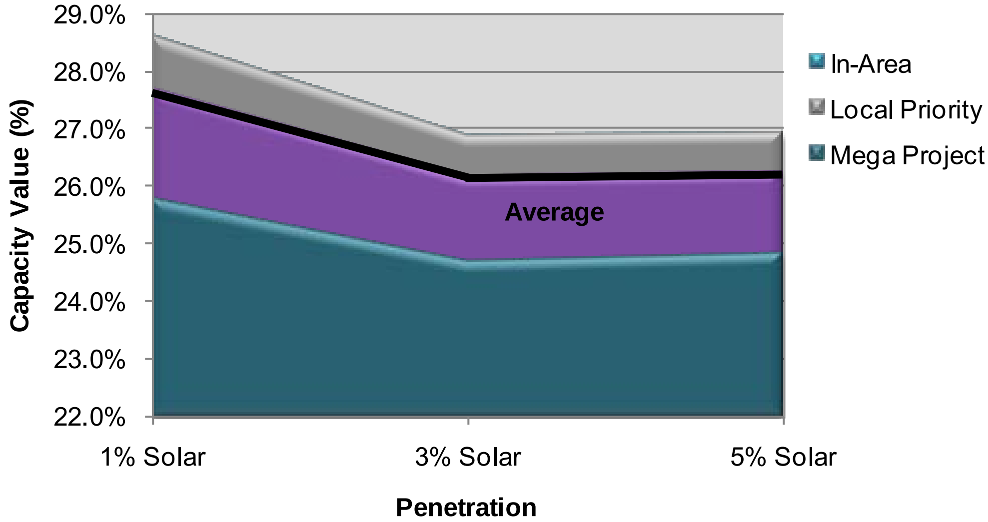
Figure 18: Photovoltaic Capacity values by scenario, 2006 shapes, perfect capacity



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

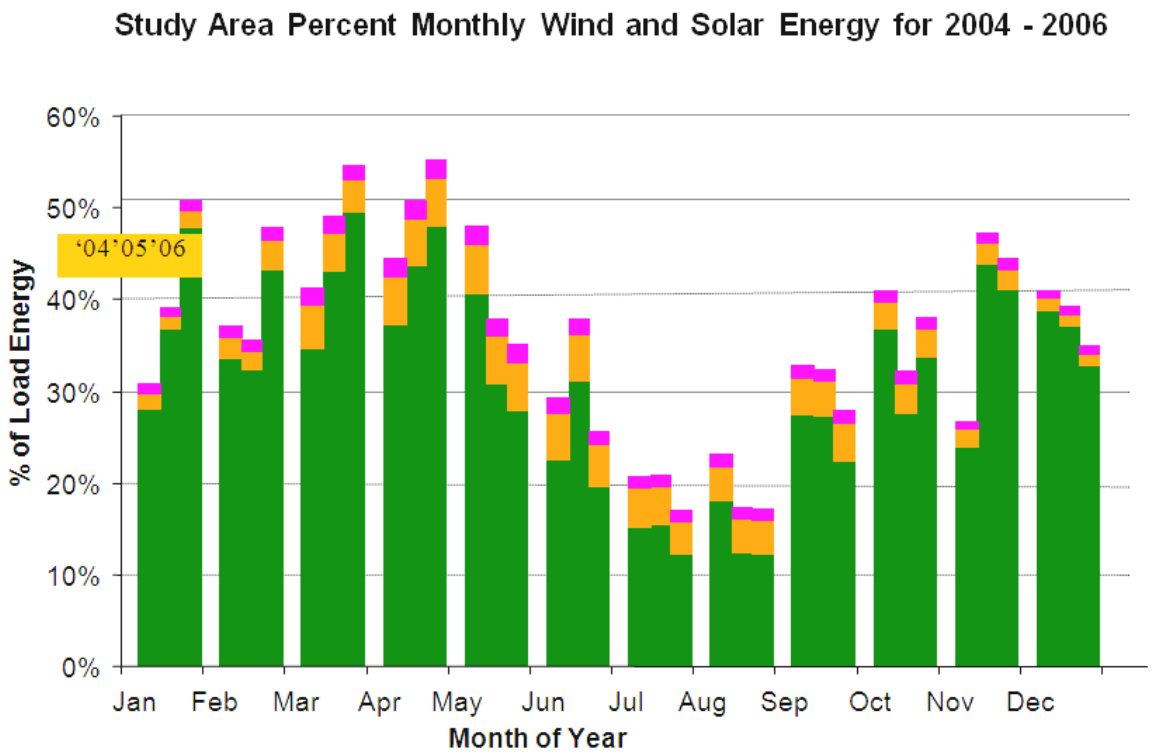


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Figure 20: Capacity value for wind, perfect capacity, daily LOLE, all years

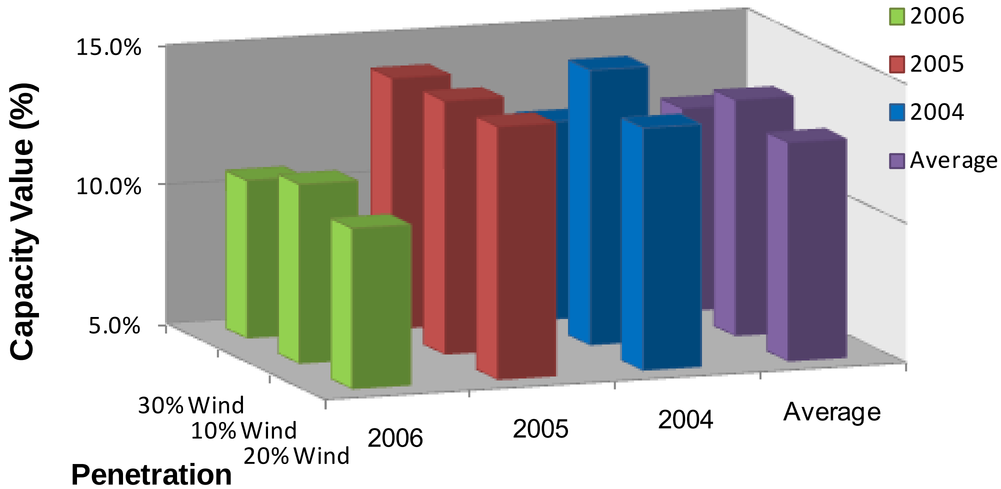

Figure 21: Capacity value for CSP with 6 hours of storage, perfect capacity, daily LOLE, all years

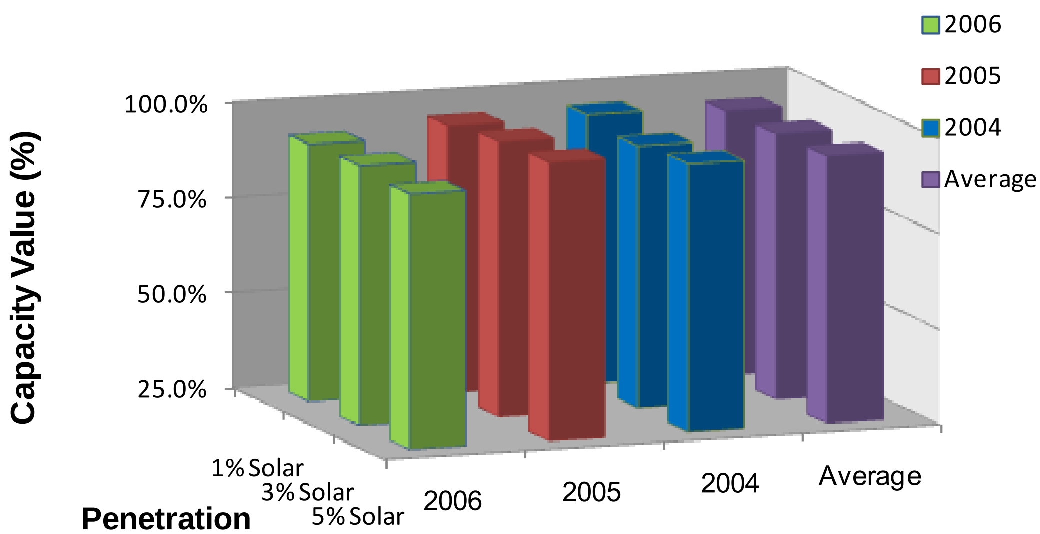

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Figure 22: Capacity value for solar with 6 hours of storage, perfect capacity, daily LOLE, all years

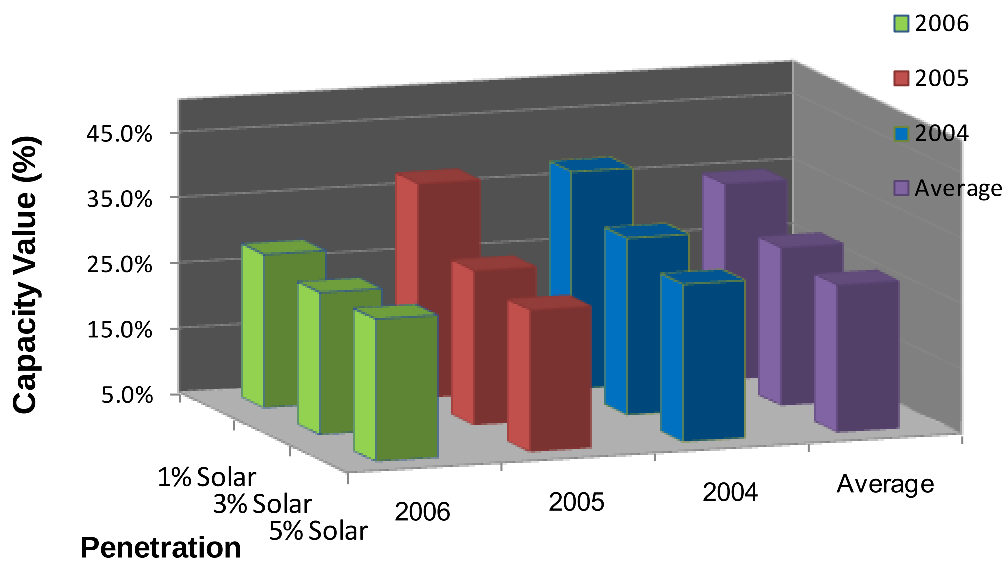
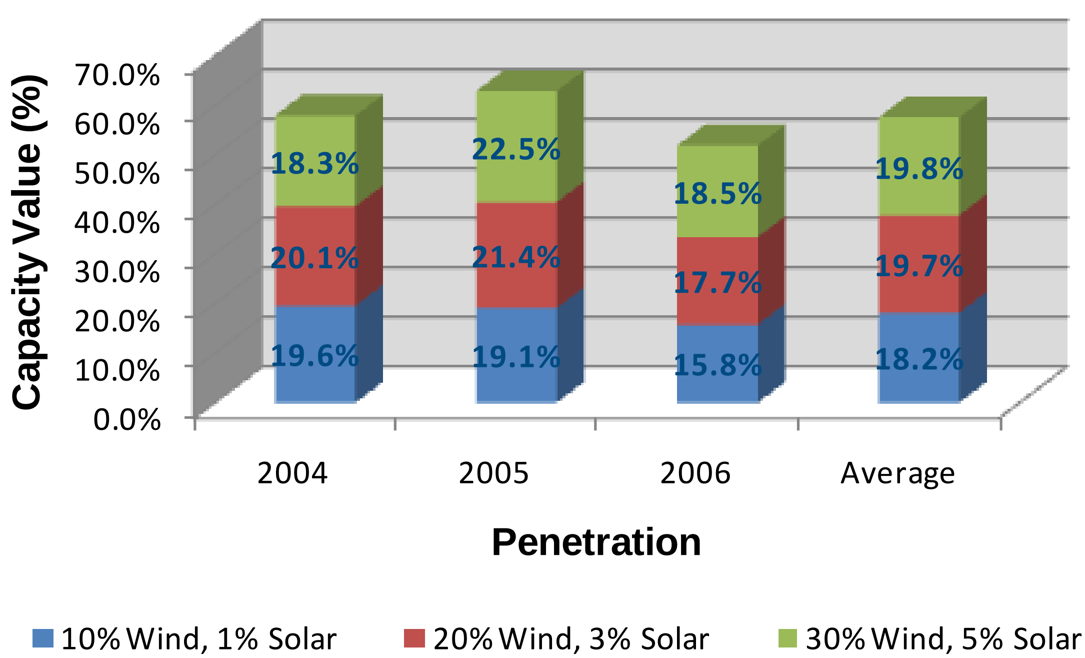


Figure 23: Combined capacity value for wind, CSP and PV, perfect capacity, daily LOLE, all years



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.

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

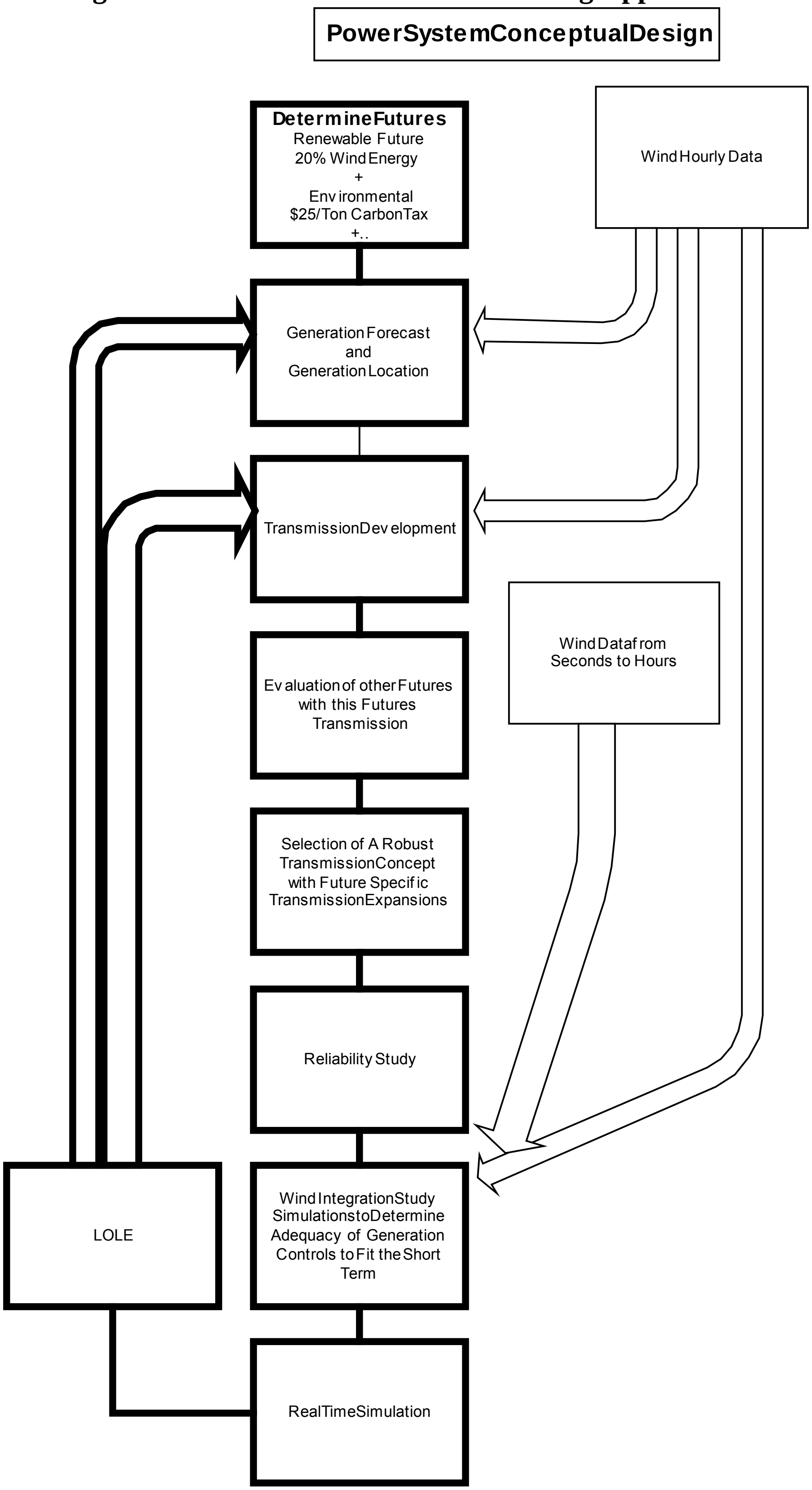

Figure 25 shows the results from the ELCC analysis. Three years of data were used for each of the EWITS scenarios. The scenarios consist of:

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.

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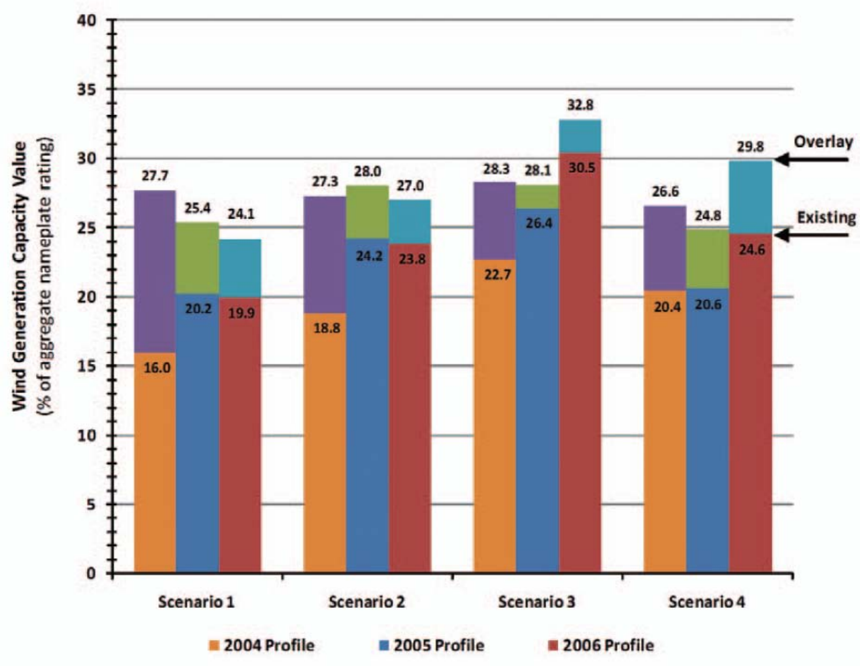
Figure 25 EWITS capacity value and impact of transmission



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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Of Opening Testimony

December 14, 2015

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Methods to Model and Calculate Capacity Contributions of Variable Generation

Oregon PUC

Michael Milligan, Ph.D.

August 17 , 2015

Acknowledgements

- **IVGTF Task Force 1.2**
- **Eduardo Ibanez**
- **Outline**
  - o NERC IVGTF 1.2
  - o NREL research and WECC 'rules of thumb'

IEEE Transactions on Power Systems, Vol 26, No 2, May 2011

564 IEEE TRANSACTIONS ON POWER SYSTEMS, VOL. 26, NO. 2, MAY 2011

Capacity Value of Wind Power

Task Force on the Capacity Value of Wind Power, IEEE Power and Energy Society
Andrew Keane, *Member, IEEE*, Michael Milligan, *Member, IEEE*, Chris J. Dent, *Member, IEEE*, Bernhard Hasche, Claudine D'Annunzio, *Student Member, IEEE*, Ken Dragoon, Hannele Holttinen, Nader Samaan, *Member, IEEE*, Lennart Söder, *Member, IEEE*, and Mark O'Malley, *Fellow, IEEE*

***Abstract*—Power systems are planned such that they have adequate generation capacity to meet the load, according to a defined reliability target. The increase in the penetration of wind generation in recent years has led to a number of challenges for the planning and operation of power systems. A key metric for generation system adequacy is the capacity value of generation. The capacity value of a generator is the contribution that a given generator makes to generation system adequacy. The variable and**

The metrics that are used for adequacy evaluation include the loss of load expectation (LOLE) and the loss of load probability (LOLP). LOLP is the probability that the load will exceed the available generation at a given time. This criterion only gives an indication of generation capacity shortfall and lacks information on the importance and duration of the outage. LOLE is the expected number of hours or days, during which the load will not

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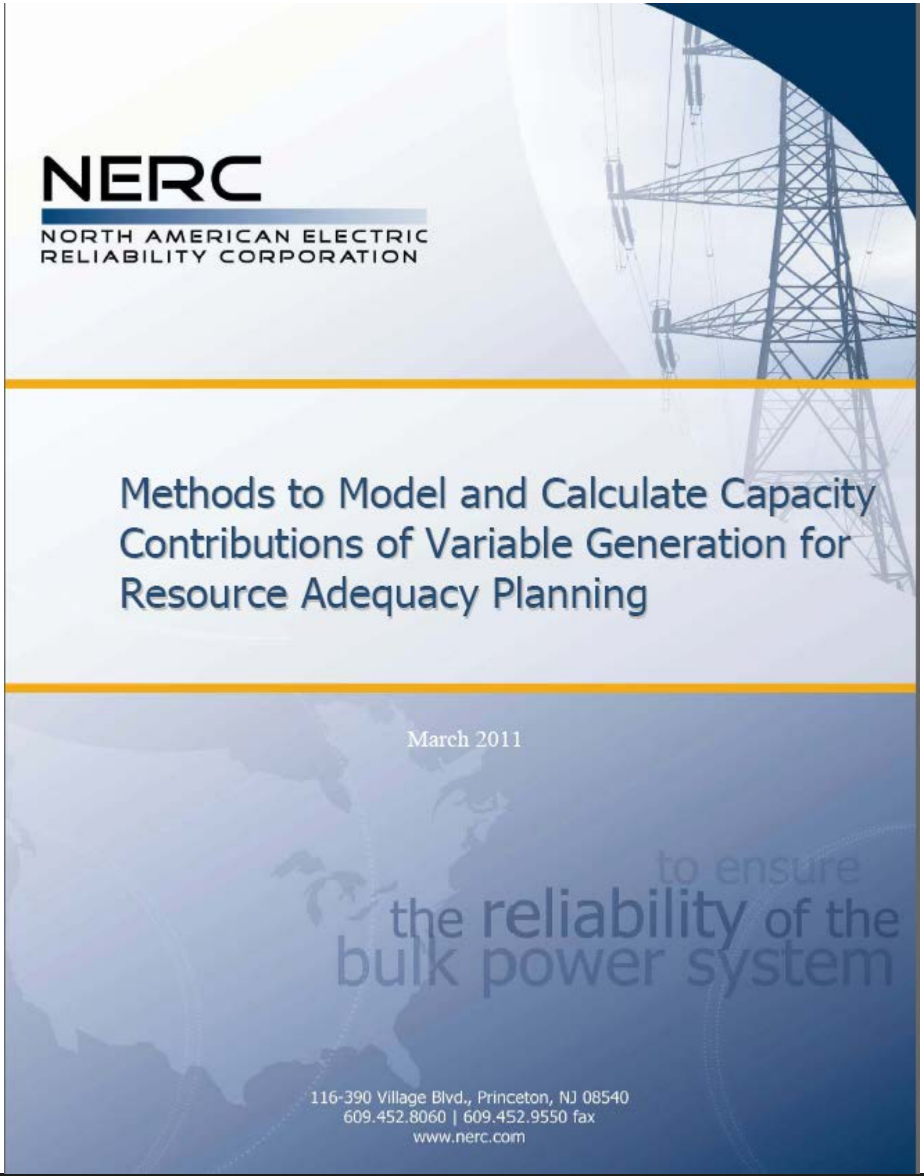
NERC Task Force Summary

NERC: Integrating Variable Generation Task Force

- **Approved by NERC's Planning Committee, 2011**
- **Recommends ELCC method**
- **Recommends research on alternative underlying LOLE-related metrics, transmission representation**



http://www.nerc.com/docs/pc/ivgtf/IVGTF1-2.pdf

Scope & Objectives

- Consistent and accurate methods are needed to calculate capacity values attributable to variable generation.

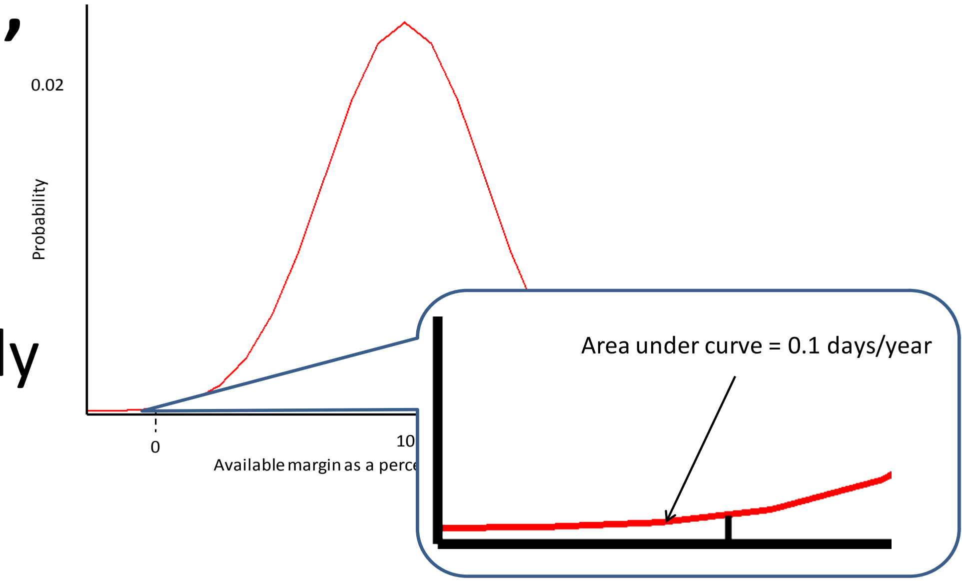
- Technical considerations for integrating variable resources into the bulk power system

NERC IVGTF Report Outline

- Introduction
- Traditional Resource Adequacy Planning
- Data Limitations
- Approximation Methods
- Ongoing Variable Generation Actions
- Conclusion and Recommendation
- (Final report approved by NERC Planning Committee March 2011

Traditional Resource Adequacy Planning

- **Loss of Load Expectation, LOLE**
  - LOLE analysis is typically performed, calculations can be done hourly or daily on a system to determine the amount of capacity that needs to be installed to meet the desired reliability target. Common target is 0.1 days/year. Fundamental metric is LOLP; basis of LOLE.



Traditional Resource Adequacy Planning

- **Loss of Load Hours, LOLH**

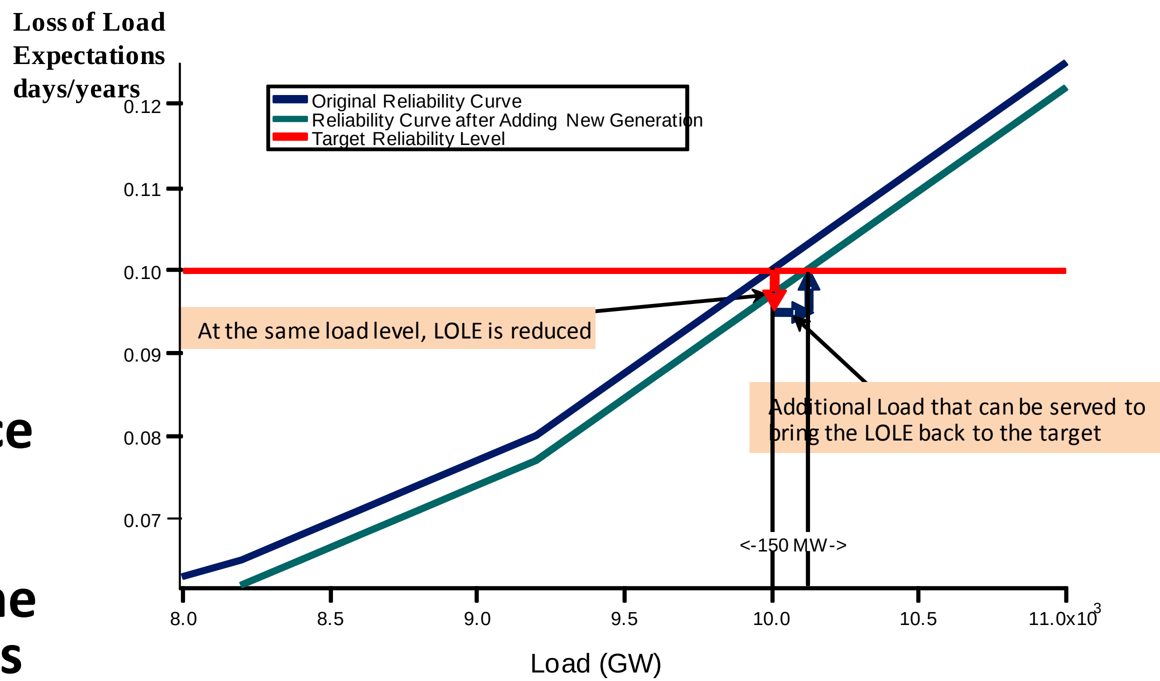
  LOLH is concerned only with the number of hours of shortfall, and does not include any dimension for persistence of an outage event and therefore there is no quantification about how many days the outage is spread over.

- **Expected unserved energy, EUE**

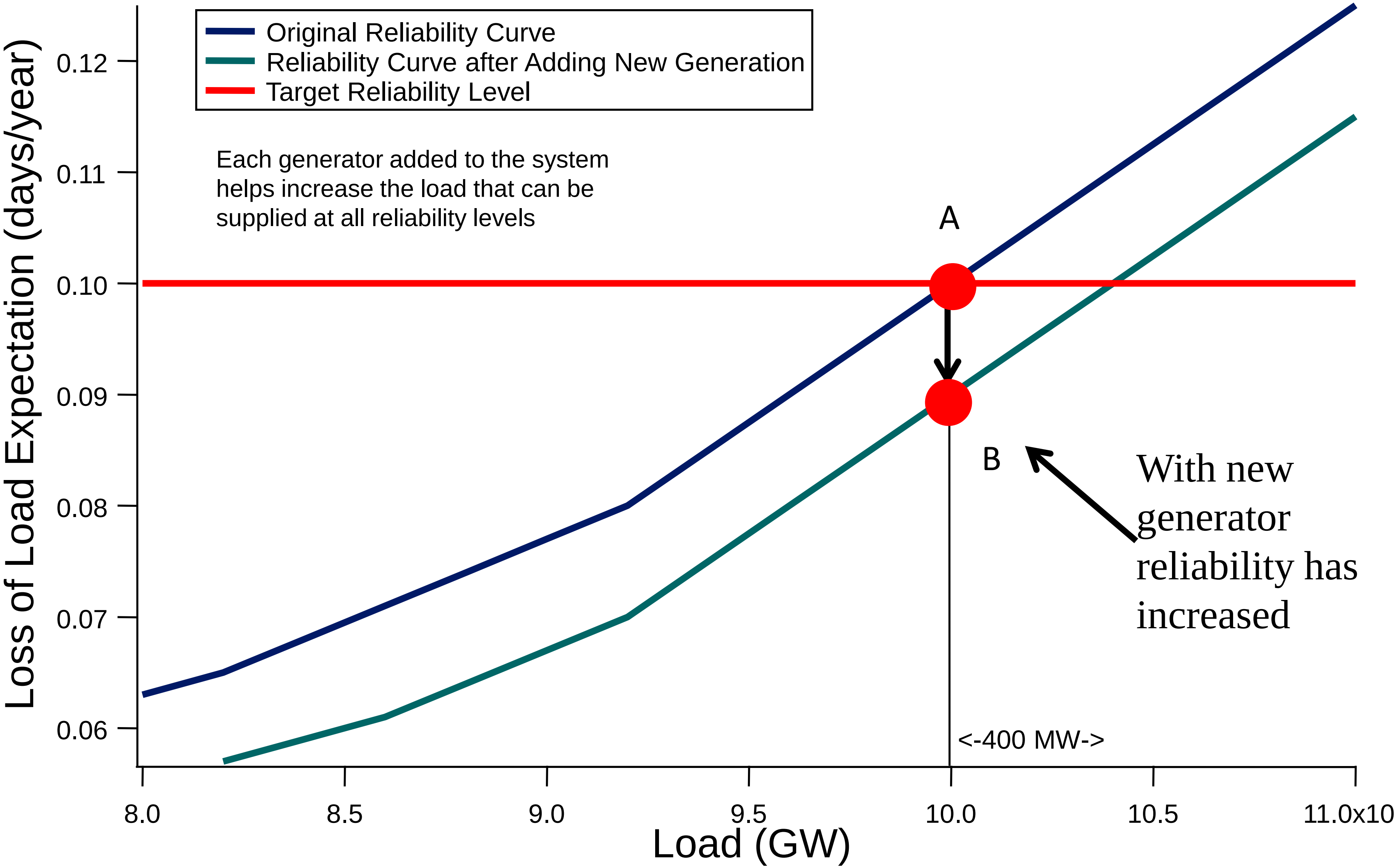
  EUE measures cumulative probabilistic energy shortfall

Traditional Resource Adequacy Planning (continued)

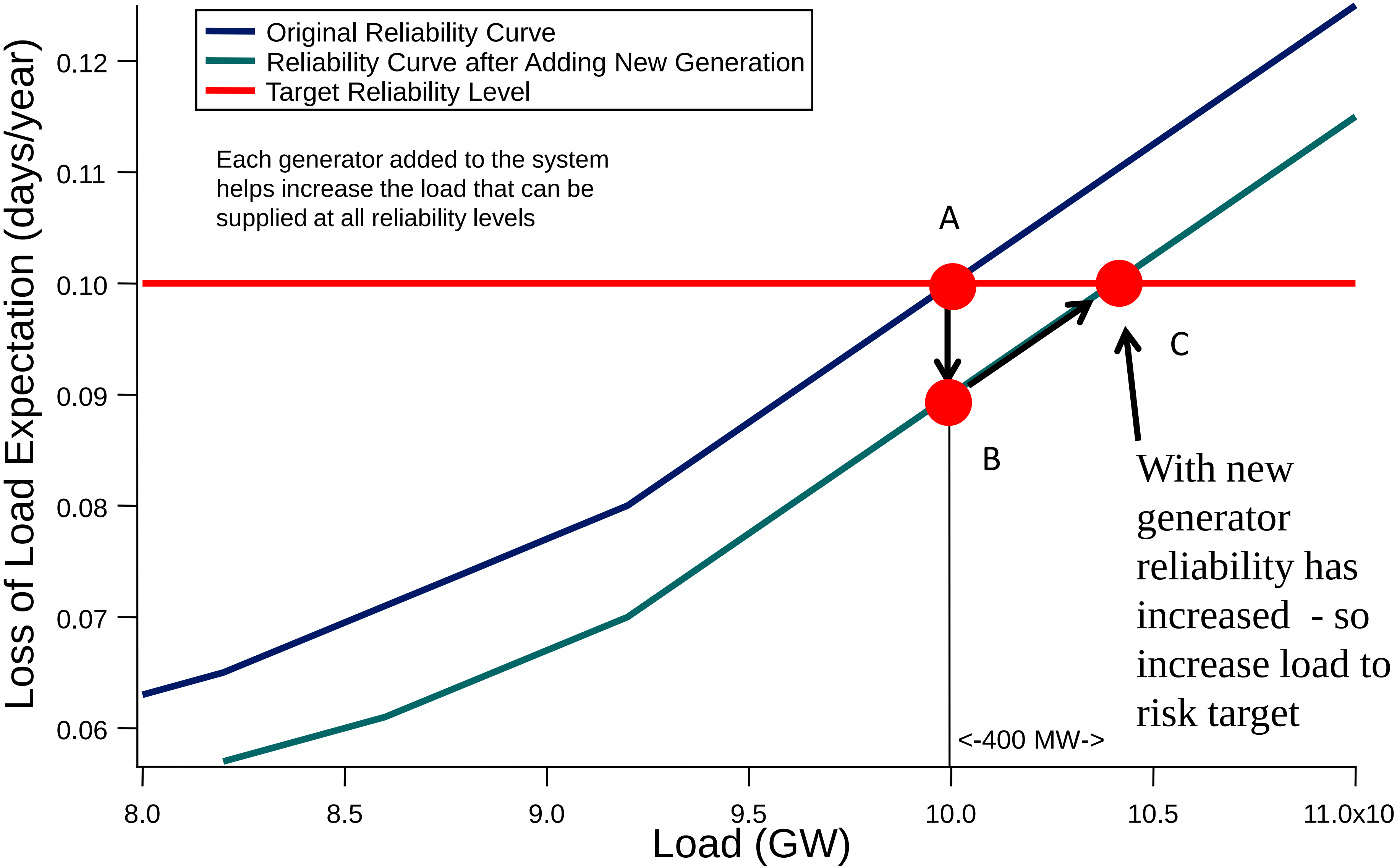
- **Effective Load Carrying Capability, ELCC**
- **ELCC essentially decomposes the contribution that an individual generator (or group of generators) makes to overall resource adequacy. A generator contributes to resource adequacy if it reduces the LOLP in some or all hours or days. Conventional generators' contribution to adequacy is typically a function of the unit's capacity and forced outage rate.**



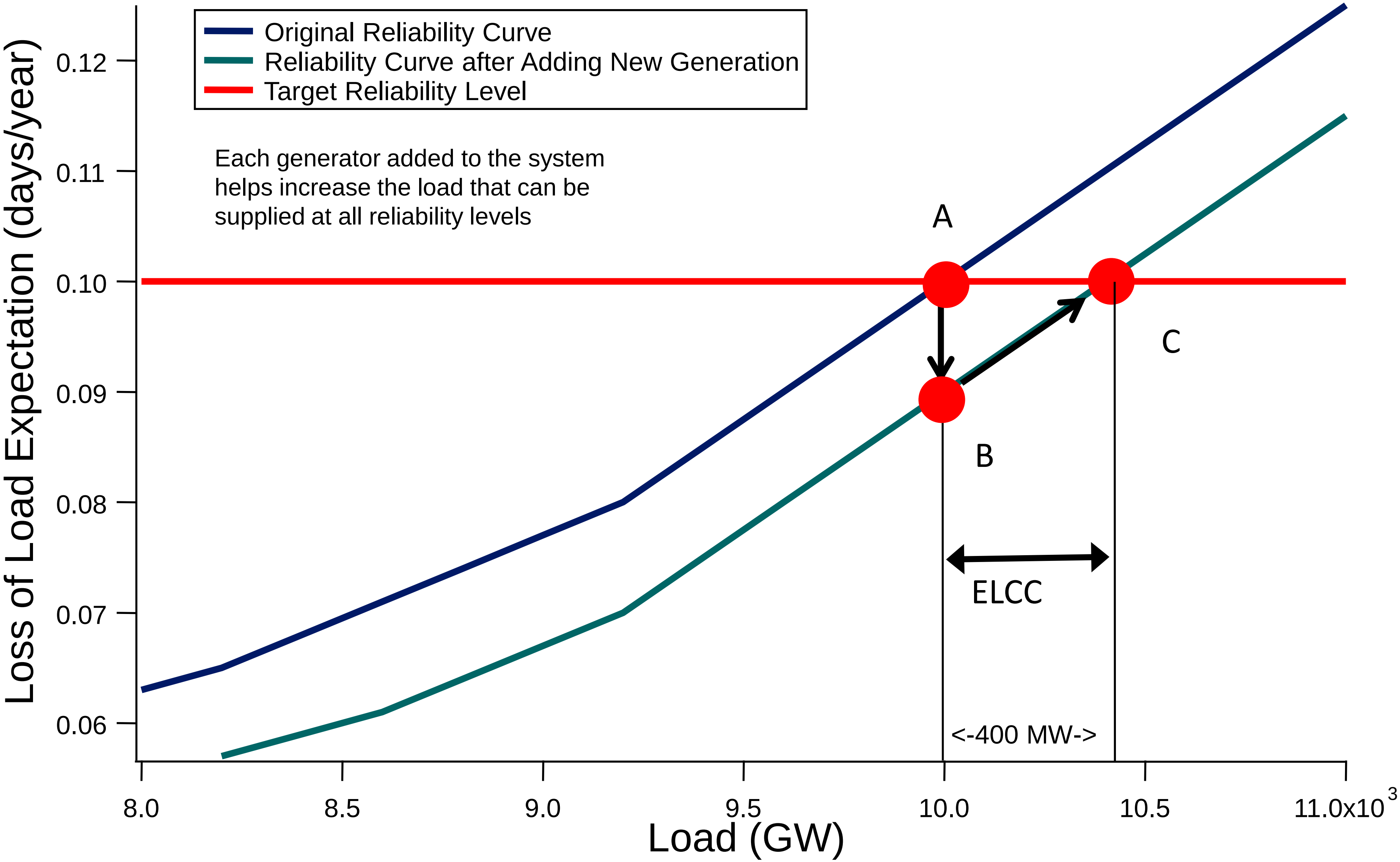
Add new resource – step 1



Add new resource – step 2



Add new resource – step 2



Approximation Methods

- **Approximations are less than ideal and often do not take LOLP or risk into account**
- **Approximation to Reliability Analysis:**

  R' = 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)
- **Time Period Methods**
  - **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**
  - **See Porter and Rogers http://www.nrel.gov/docs/fy12osti/54338.pdf**

Data Limitations

- **Data**
  - Thermal Generation does exist
    - Long-term forced outage rates
    - GADS
  - ***Wind and Solar does not have sufficient long term data***
- **Need for data from variable generation**
  - Collected by NERC's GADS
  - Currently does not satisfy requirements for capacity valuation of variable generation

Data Requirements: Wind, Solar, and Load

- Weather is common driver
- Hourly wind, solar, and load data must be from same year for consistent analysis and plausible results
- Use of meso-scale weather models or actual VG production is state of the art (same as integration studies)
- Preserves underlying correlations between wind, solar, and load with temperature, other weather phenomena

Conclusions and Recommendations

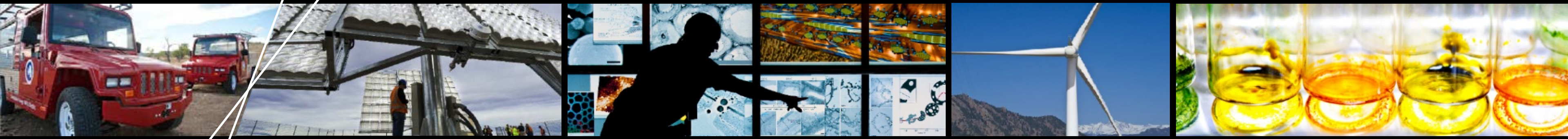
- **Additional research to equate traditional reliability targets (such as 0.1day/year) to alternative metrics is recommended.**
- **Alternative approaches and assumptions regarding the treatment of interconnected systems should be transparent to the analysis**

Conclusions and Recommendations (continued)

- 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 0.1 days/year target (or other adopted target) and a given Planning Reserve Margin do not change as a result of an evolving resource mix.

Conclusions and Recommendations (continued)

- **Simplified approaches should be benchmarked and calibrated to the rigorous ELCC calculations to ensure the validity of the approximation.**
- **NERC should design and implement a way to collect high-quality variable generation data that would help inform calculations of capacity value. The development of such a database should consider defining relevant time periods for the variable generation data.**

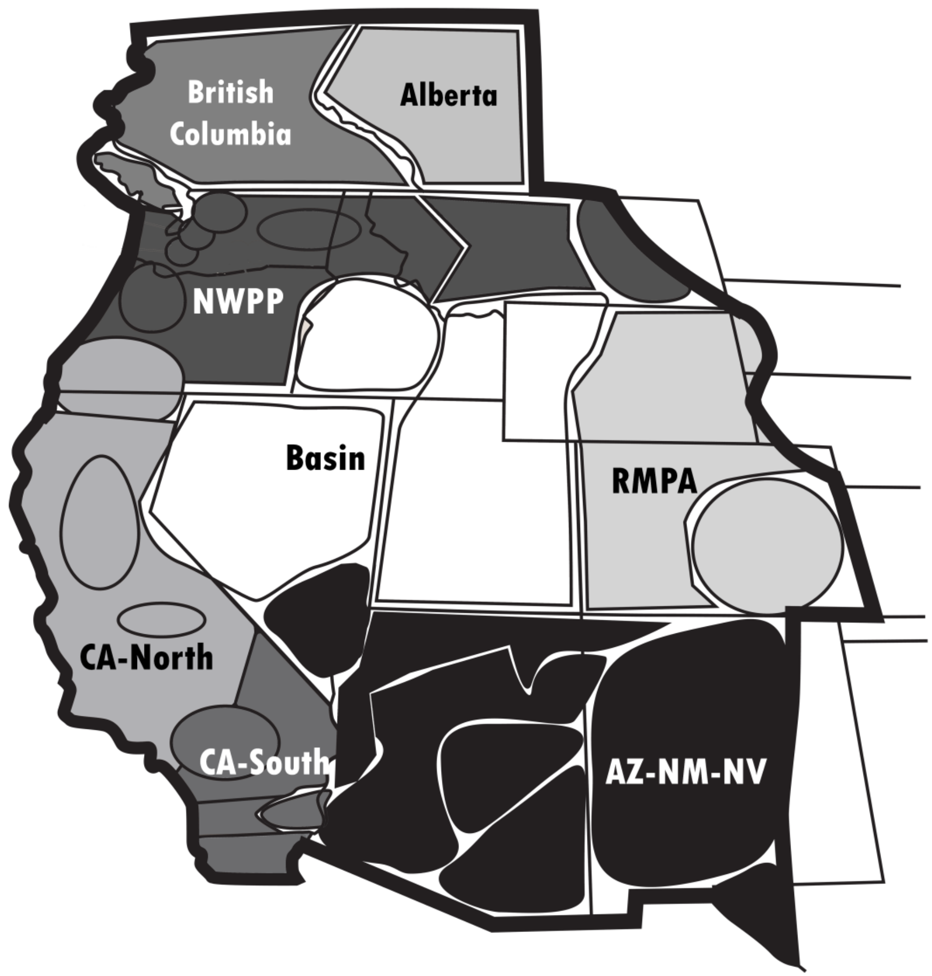


Evaluation of WECC Rules of Thumb for Resource Adequacy for Wind and Solar

Numerical Example

- **Comparison of metrics and effect on capacity value**
- **Using WECC's Transmission Expansion Planning Policy Committee (TEPPC) 2024**
  - o Long-term transmission study for the U.S. Western Interconnection

Footprint and pools



Tool: REPRA

- **Renewable Energy Probabilistic Resource Assessment tool (REPRA)**
  - Include variable generation in traditional probabilistic-based methods
  - Allow comparison of alternative targets, metrics (LOLE, ENS, LOLH, etc.)
  - Answer questions from the IVGTF report http://www.nerc.com/files/IVGTF1-2.pdf
  - Available as open-source package for R statistical software
- **More information:**
  - Ibanez, Milligan, "Impact of Transmission on Resource Adequacy in Systems with Wind and Solar Power," www.nrel.gov/docs/fy12osti/53482.pdf
  - –, "Probabilistic Approach to Quantifying the Contribution of Variable Generation and Transmission to System Reliability," http://www.nrel.gov/docs/fy12osti/56219.pdf

Definition of pools and reserve margins

Pool	Includes	Summer Margin	Winter Margin
AZ-NM-NV	Arizona, New Mexico, Southern Nevada	13.6%	14.0%
Basin	Idaho, Northern Nevada, Utah	13.7%	13.7%
Alberta	Alberta	12.6%	13.9%
BC	British Columbia	12.6%	13.9%
CA-North	Northern California, San Francisco, SMUD	15.0%	12.1%
CA-South	Southern California Edison, San Diego Gas & Electric, LADWP, Imperial Irrigation District	15.2%	11.0%
NWPP	Pacific Northwest, Montana	17.5%	19.2%
RMPA	Colorado, Wyoming	15%	15.9%

Contribution to Resource Adequacy

Capacity credit by technology and pool that TEPPC uses to meet the reserve margin criteria

Generation Type	AZ-NM-NV	Basin	Alberta	BC	CA-North	CA-South	NWPP	RMPA
Biomass RPS	100%	100%	100%	100%	66%	65%	100%	100%
Geothermal	100%	100%	100%	100%	72%	70%	100%	100%
Small Hydro RPS	35%	35%	35%	35%	35%	35%	35%	35%
Solar PV	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**
Solar CSP0	90%	95%	95%	95%	72%	72%	95%	95%
Solar CSP6	95%	95%	95%	95%	100%	100%	95%	95%
Wind	**10%**	**10%**	**10%**	**10%**	**16%**	**16%**	**5%**	**10%**
Hydro	70%	70%	90%	90%	70%	95%	70%	70%
Pumped Storage	100%	100%	100%	100%	100%	100%	100%	100%
Coal	100%	100%	100%	100%	100%	100%	100%	100%
Nuclear	100%	100%	100%	100%	100%	100%	100%	100%
Combined Cycle	95%	95%	100%	95%	95%	95%	95%	95%
Combustion Turbine	95%	95%	100%	95%	95%	95%	95%	95%
Other Steam	100%	100%	100%	100%	100%	100%	100%	100%
Other	100%	100%	100%	100%	100%	100%	100%	100%
Negative Bus Load	100%	100%	100%	100%	100%	100%	100%	100%
Dispatchable DSM	100%	100%	100%	100%	100%	100%	100%	100%

Contribution to Resource Adequacy

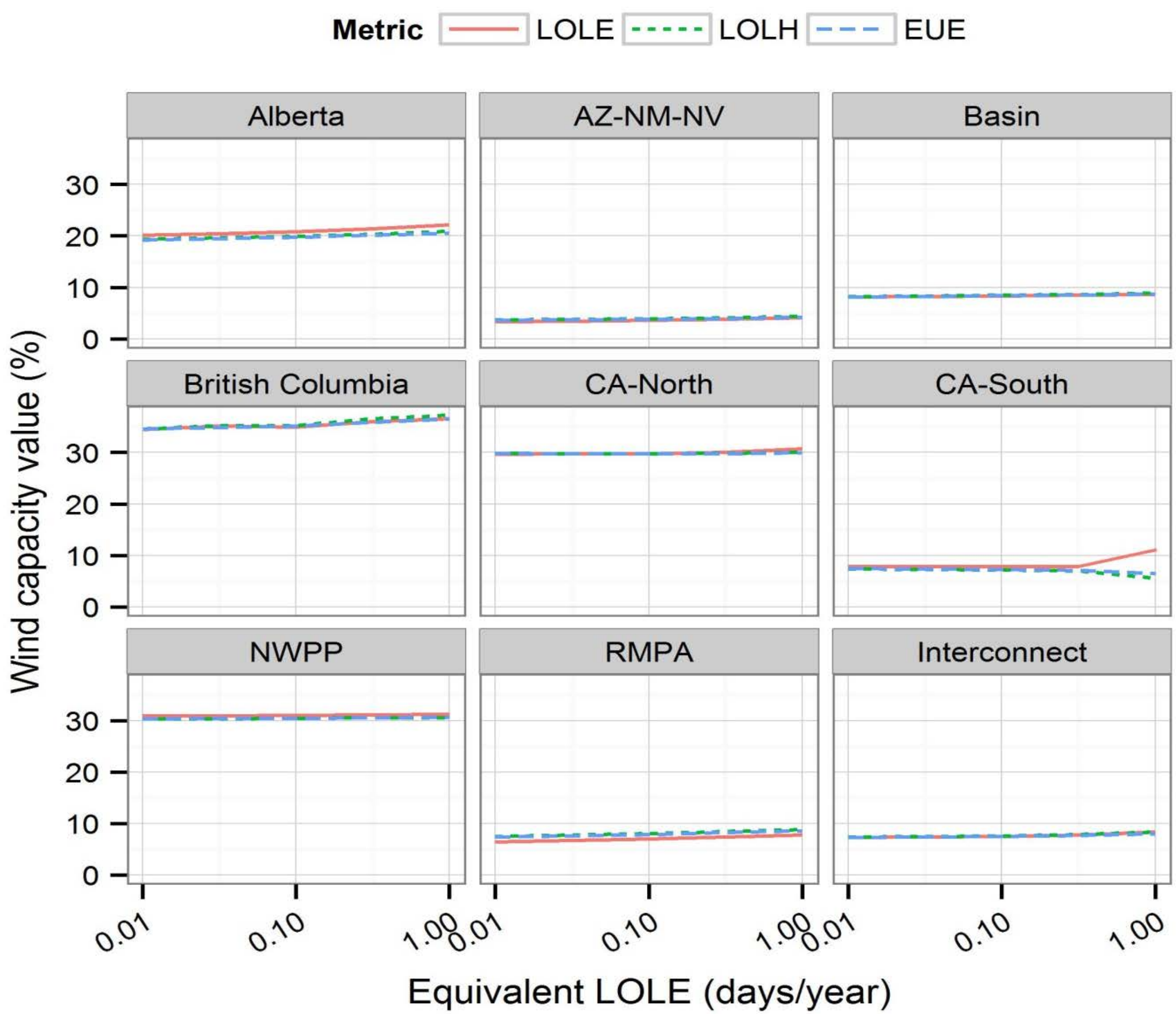
Capacity credit by technology and pool that TEPPC uses to meet the reserve margin criteria

Generation Type	AZ-NM-NV	Basin	Alberta	BC	CA-North	CA-South	NWPP	RMPA
Biomass RPS	100%	100%	100%	100%	66%	65%	100%	100%
Geothermal	100%	100%	100%	100%	72%	70%	100%	100%
Small Hydro RPS	35%	35%	35%	35%	35%	35%	35%	35%
Solar PV	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**	**60%**
Solar CSP0	90%	95%	95%	95%	72%	72%	95%	95%
Solar CSP6	95%	95%	95%	95%	100%	100%	95%	95%
Wind	**10%**	**10%**	**10%**	**10%**	**16%**	**16%**	**5%**	**10%**
Hydro	70%	70%	90%	90%	70%	95%	70%	70%
Pumped Storage	100%							100%
Coal	100%							100%
Nuclear	100%							100%
Combined Cycle	95%							95%
Combustion Turbine	95%							95%
Other Steam	100%							100%
Other	100%							100%
Negative Bus Load	100%	100%	100%	100%	100%	100%	100%	100%
Dispatchable DSM	100%	100%	100%	100%	100%	100%	100%	100%

Solar PV = 60% everywhere

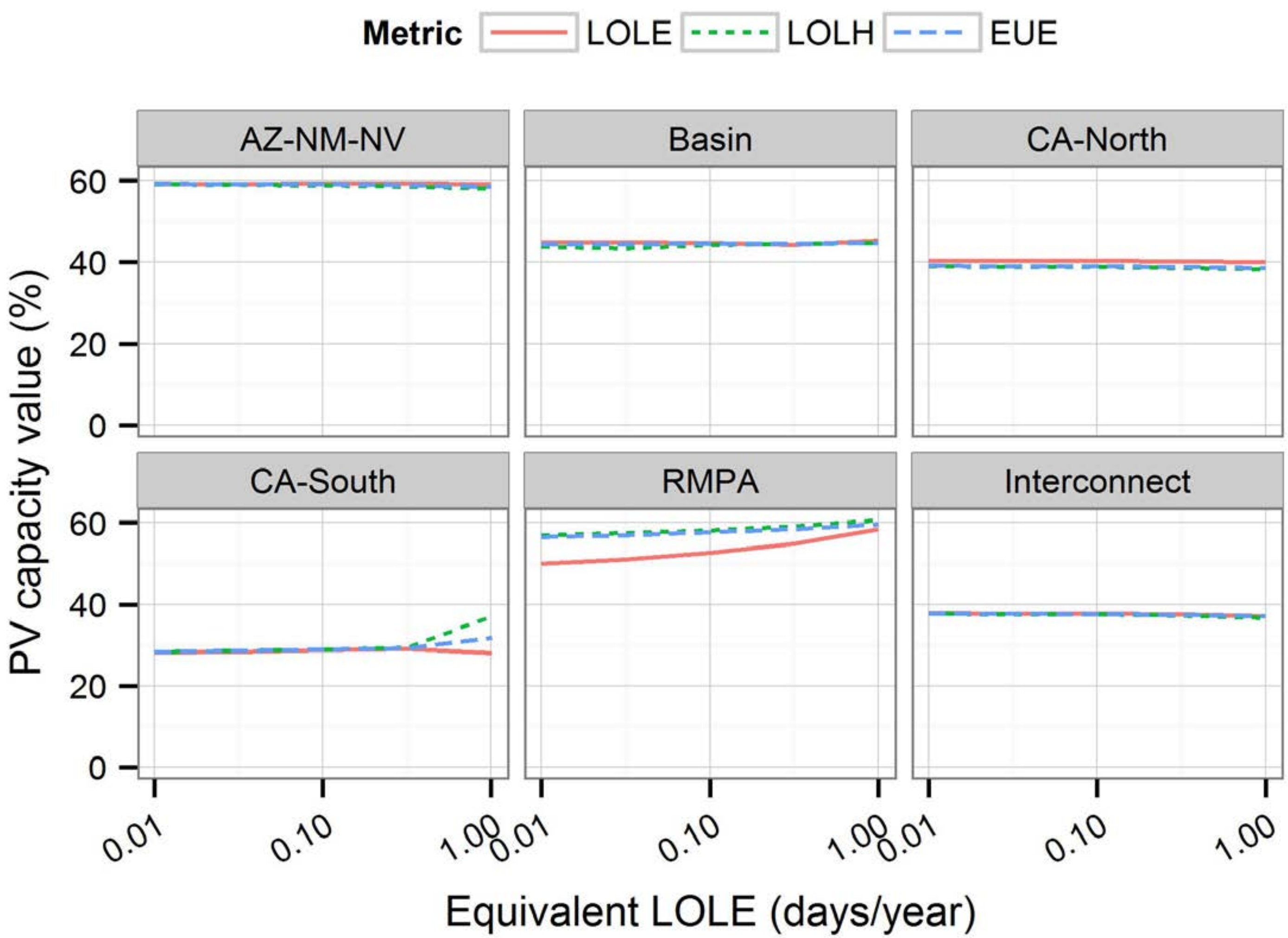
Wind varies from 5-16%

Wind capacity value for different metrics



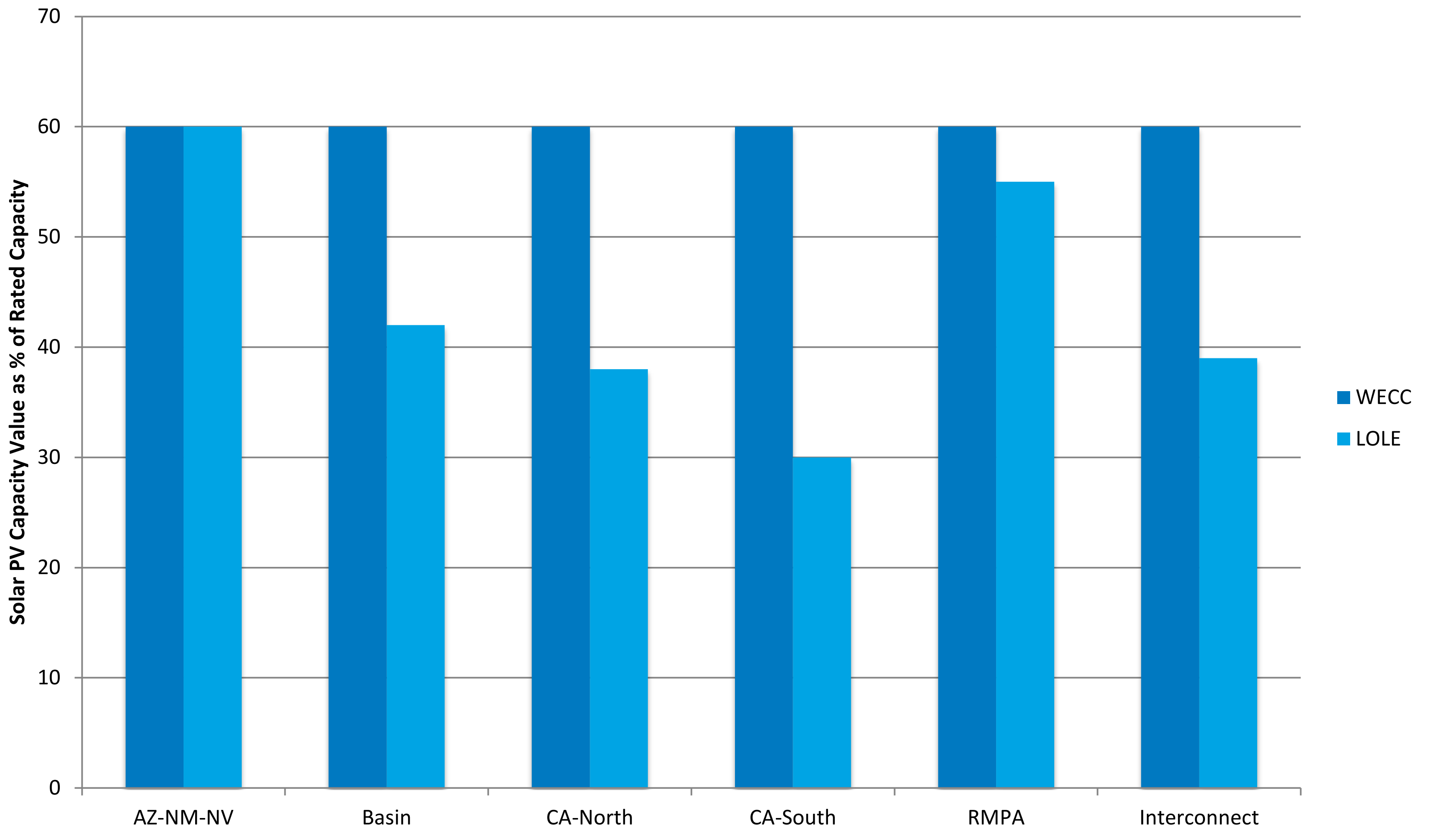
TEPPC assumed 10% capacity value (except 16% In CA and 5% NWPP)

PV capacity value for different metrics

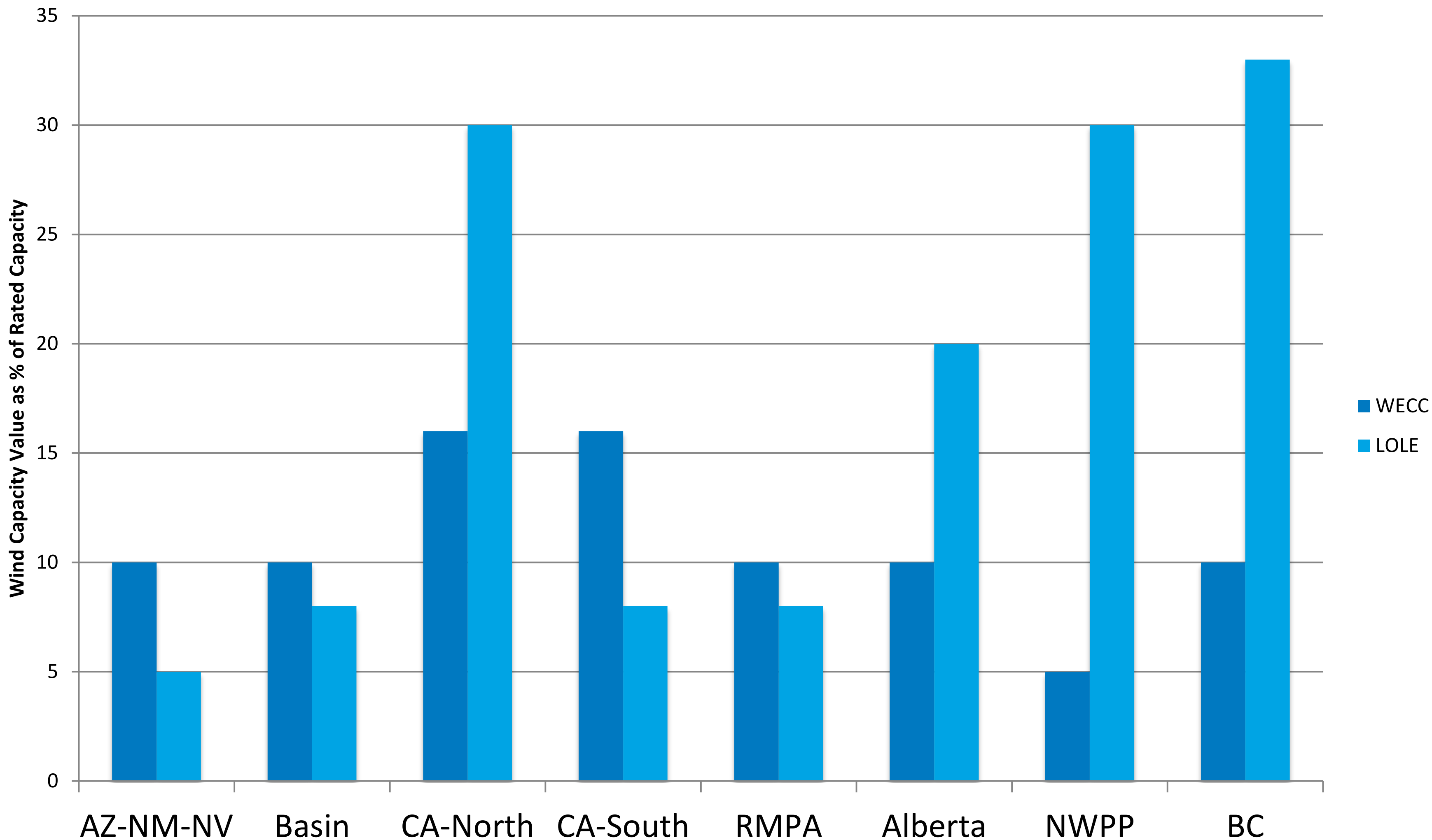


TEPPC assumed 60% capacity value at all locations

PV: Comparison of WECC Rules of Thumb and ELCC



Wind: Comparison of WECC Rules of Thumb and ELCC



Conclusions – Resource Adequacy Metrics

- **Estimating resource adequacy levels in the presence or renewables is an open area of research**
- **Capacity values are not very sensitive to metric or adequacy level selection**
- **Calculated CV were smaller than TEPPC assumptions; TEPPC cases might be slightly underbuilt**

WECC may want to consider:

- **Adopting these capacity values by type of resource and zone as new rules of thumb**
  - Subject to periodic revision
- **Utilizing NREL's REPRA (open source) model to complement existing modeling resources in TEPPC process**
- **Utilizing an alternative approach to incorporate capacity valuation into the TEPPC process**

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AN EVALUATION OF SOLAR VALUATION METHODS USED IN UTILITY PLANNING AND PROCUREMENT PROCESSES

Andrew D. Mills and Ryan Wiser

Environmental Energy Technologies Division

April 2013

Proceedings of ASES Annual Meeting, Baltimore, MD, April 19, 2013.

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DISCLAIMER

AN EVALUATION OF SOLAR VALUATION METHODS USED IN UTILITY PLANNING AND PROCUREMENT PROCESSES

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ABSTRACT

As renewable technologies mature, recognizing and evaluating their economic value will become increasingly important for justifying their expanded use. This paper reviews a recent sample of U.S. load-serving entity (LSE) planning studies and procurement processes to identify how current practices reflect the drivers of solar's economic value. In particular, we analyze the LSEs' treatment of the capacity value, energy value, and integration costs of solar energy; the LSEs' treatment of other factors including the risk reduction value of solar, impacts to the transmission and distribution system, and options that might mitigate solar variability and uncertainty; the methods LSEs use to design candidate portfolios of resources for evaluation within the studies; and the approaches LSEs use to evaluate the economic attractiveness of bids during procurement.

We found that many LSEs have a framework to capture and evaluate solar's value, but approaches varied widely: only a few studies appeared to complement the framework with detailed analysis of key factors such as capacity credits, integration costs, and tradeoffs between distributed and utility-scale photovoltaics. Full evaluation of the costs and benefits of solar requires that a variety of solar options are included in a diverse set of candidate portfolios. We found that studies account for the capacity value of solar, though capacity credit estimates with increasing penetration can be improved. Furthermore, while most LSEs have the right approach and tools to evaluate the energy value of solar, improvements remain possible, particularly in estimating solar integration costs used to adjust energy value. Transmission and distribution benefits, or costs, related to solar are rarely included in studies. Similarly, few LSE planning studies can reflect the full range of potential benefits from adding thermal storage and/or natural gas augmentation to concentrating solar power plants.

1. INTRODUCTION

Recent declines in the cost of photovoltaic (PV) energy, increasing experience with the deployment of concentrating solar power (CSP), the availability of tax-based incentives for solar, and state renewables portfolio standards (RPS) (some with solar-specific requirements) have led to increased interest in solar power among U.S. load-serving entities (LSEs). This interest is reflected within LSE planning and procurement processes and in a growing body of literature on the economic value of solar energy within utility portfolios [1-8]. This report identifies how current LSE planning and procurement practices reflect the drivers of solar's economic value identified in the broader literature. This comparison can help LSEs, regulators, and policy makers identify ways to improve LSE planning and procurement.

The paper summarizes a detailed review of 16 planning studies and nine documents describing procurement processes created during 2008–2012 by LSEs interested in solar power among other options (Table 1) [9]. We first summarize the typical approach used by LSEs in planning studies and procurement processes. We then analyze the LSEs' treatment of the capacity value, energy value, and integration costs of solar energy; the LSEs' treatment of other factors including the risk reduction value of solar, impacts to the transmission and distribution system, and options that might mitigate solar variability and uncertainty; the methods LSEs use to design candidate portfolios of resources for evaluation within the studies; and the approaches LSEs use to evaluate the economic attractiveness of bids during procurement. We offer several recommendations that could help LSEs improve planning studies and procurement processes.

The intended audience for this paper is LSE planners and their regulators that often oversee or approve planning studies and resource procurement, stakeholders that are involved with or provide input to public planning studies, and renewable energy project developers or equipment manufacturers.

This paper builds on previous analysis of the treatment of renewable energy [10] and carbon regulatory risk [11] in utility resource plans in the western United States, and a survey of the treatment of solar in utility procurement processes [12]. Research into incorporating renewables, other non-conventional technologies, and uncertainty into utility planning has a long history and remains active. Hirst and Goldman, for example, review best practices for integrated resource planning and distinguish it from traditional utility planning [13].

TABLE 1: PLANNING STUDIES AND PROCUREMENT PRACTICES REVIEWED

Load-serving entity	Planning study (yr)	Procurement practices (yr)
APS	2012	2011
CA IOU Process	2010	2011
Duke Energy Carolinas	2011	-
El Paso Electric	2012	2011
Idaho Power	2011	-
IID	2010	-
LADWP	2011	2012
NPCC	2010	-
NV Energy	2012	2010
PacifiCorp	2011	2010
PGE	2009	2012
PSCo	2011	2011
PNM	2011	2011
Salt River Project	2010	-
Tri-State G&T	2010	-
TEP	2012	-

2. SUMMARY OF STEPS USED BY LSES IN PLANNING STUDIES AND PROCUREMENT PROCESSES

Many of the LSEs followed a similar set of steps (Fig. 1) that began with an assessment of demand forecasts, generation options, fuel price forecasts, and regulatory requirements over a planning horizon. Based on this assessment, LSEs created candidate resource portfolios that satisfy these needs and regulatory requirements. These candidate portfolios were typically created using one of three methods:

- Manual creation based on engineering judgment or stakeholder requests
- Creation using capacity-expansion models based on deterministic future assumptions
- Creation using an intermediate approach in which resource options are ranked according to metrics defined by each LSE

The present value of the revenue requirement (PVRR) of candidate portfolios was then evaluated in detail. The PVRR of each portfolio was based primarily on the capital cost of each portfolio and the variable cost of dispatching each portfolio to maintain a balance between supply and demand over the planning period. The variable cost was commonly evaluated by simulating the dispatch of the portfolio using a production cost model. Many LSEs used scenario analysis or Monte-Carlo analysis (or some combination of both) to evaluate the exposure of each portfolio to changes in uncertain factors such as fossil-fuel prices, demand, or carbon dioxide prices. LSEs then chose a preferred portfolio based on the relative performance of the candidate portfolios. The preferred portfolio was often determined by balancing a desire for both low costs and low risks. During procurement, LSEs often solicited bids for resources that matched the characteristics of resources identified in the preferred portfolio.

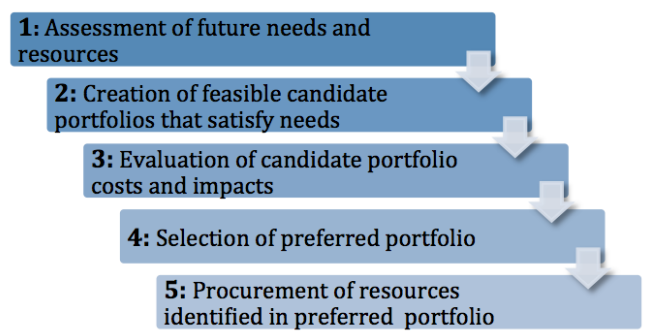


Fig. 1: General steps followed by LSEs in planning and procurement

3. SOLAR TECHNOLOGIES CONSIDERED IN PLANNING AND PROCUREMENT

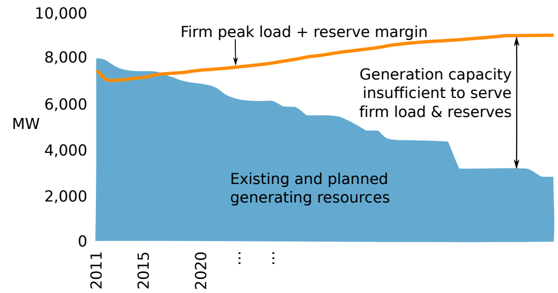
Among our sample, many LSEs considered PV and CSP with or without thermal storage or natural gas augmentation (Table 2). The PV technologies considered by LSEs were not always described in detail. When they were described, LSEs typically considered fixed PV or single-axis tracking PV; some also distinguished between distributed and utility-scale PV. One LSE considered a PV plant coupled with a lead-acid battery. The CSP technology was usually based on a parabolic trough or a solar power tower configuration. One LSE considered a solar chimney, and another LSE considered a solar thermal gas hybrid (a natural gas power plant with solar concentrators that preheat water used in the plant's steam cycle).

TABLE 2: SOLAR TECHNOLOGIES INCLUDED IN ASSESSMENT OF POTENTIAL FUTURE RESOURCES

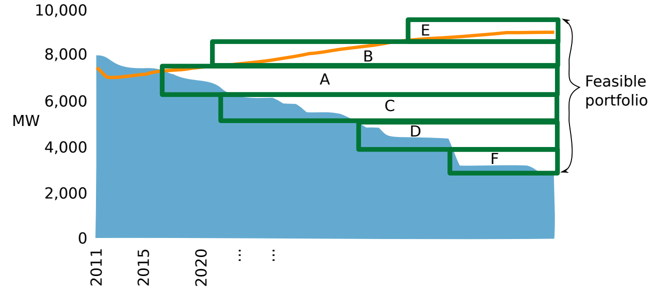
Technology Category	Variation	Integrated thermal storage	Natural gas firing in boiler
PV	Fixed	N/A	N/A
	Single-axis tracking	N/A	N/A
	With lead acid battery	N/A	N/A
CSP	Trough	None	No
	Trough	None	Yes
	Trough	3 hours	No
	Trough	6-8 hours	No
	Power tower	7 hours	No
	Solar chimney	None	No
Solar thermal gas hybrid plants		N/A	N/A

4. RECOGNITION OF SOLAR CAPACITY VALUE IN PLANNING STUDIES

In regions where solar generation is well correlated with periods of high demand, one of the main contributors to solar's economic value is the capacity value. The capacity value of solar reflects the avoided costs from reducing the need to build other capacity resources, often combustion turbines (CTs), to meet peak demand reliably. LSEs usually added sufficient capacity to meet the peak load plus a planning reserve margin in each candidate portfolio (Fig. 2). Portfolios that included solar need not include as much capacity from other resources, so solar offset some of the capital cost that would otherwise be included in the portfolio's PVRR. Thus, solar's capacity value was based in part on the capital cost of the avoided capacity resources and the timing of the need for new capacity.



(a)



(b)

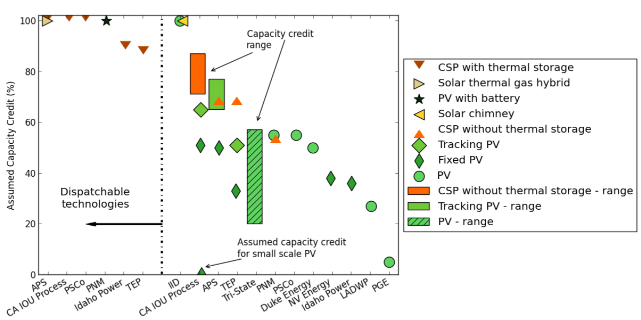
Fig. 2: Example of LSE assessment of (a) expected future peak loads and existing resources and (b) the creation of a feasible candidate portfolio that meets those needs (adapted from PSCo)

The capacity value of solar was affected by the study methodology. In at least one case, the LSE assumed that the generating resources used for capacity were very "lumpy" (i.e., only available in blocks of 290 MW or greater). As a result, adding a small amount of solar to a portfolio could not change the timing or amount of other capacity resources required; thus, the same amount of CT capacity was needed with or without the inclusion of solar, even though the LSE recognized that some of the solar nameplate capacity could contribute to meeting peak loads. Including capacity resources that are available in smaller size increments—e.g., 50-MW CTs, which were modeled by other LSEs—or modeling the value of selling excess capacity to neighboring LSEs better recognizes solar's capacity value.

5. ESTIMATES OF SOLAR CAPACITY CREDIT IN PLANNING STUDIES AND BROADER LITERATURE

The primary driver of solar's capacity value is the capacity credit: the percentage of the solar nameplate capacity that can be counted toward meeting the peak load and planning reserve margin. The capacity credit assigned to solar technologies by the LSE determines how much capacity from an alternative resource can be avoided by including solar in a portfolio. For example, a capacity credit of 50% for PV indicates that a 100-MW PV plant can contribute roughly the same toward meeting peak load and the planning reserve margin as a 50-MW CT. Analysis in the literature shows that the capacity credit of solar largely depends on the correlation of solar production with LSE demand, meaning the capacity credit varies by solar technology (e.g., PV vs. CSP with thermal storage), configuration (e.g., single-axis tracking PV vs. fixed PV), and LSE (e.g., summer afternoon peaking vs. winter night peaking) [14-22]. As expected, the capacity credit assigned by LSEs to solar in planning studies varied by technology, configuration, and LSE (Fig. 3). However, few studies appeared to use detailed loss of load probability (LOLP) studies to determine the capacity credit of solar. Instead, most LSEs relied on analysis of the solar production during peak-load periods or assumptions based on rules of thumb. The reliance on assumptions or simple approximation methods to assign a capacity credit to solar may also contribute to much of the variation in capacity credit across studies.

Only one LSE, Arizona Public Service (APS), appeared to account for changes in the capacity credit of solar with increasing penetration. Analysis in the broader literature finds that solar capacity credit decreases with increasing solar penetration, particularly for PV and CSP without thermal storage or natural gas augmentation (Fig. 4). One of the main factors in the literature that distinguishes the economic value of CSP with thermal storage from the economic value of PV and CSP without thermal storage or natural gas augmentation is the ability of CSP with thermal storage to maintain a high capacity credit with increasing penetration. If LSE planning studies do not reflect this difference in capacity credit with increasing penetration, then the difference in economic value among different solar technologies will not be reflected in their planning studies.



Note: Imperial Irrigation District (IID) appears to assume a 100% capacity credit for PV and a solar chimney. Capacity credit for APS represent capacity credit applied at low penetration level; capacity credit is reduced with higher PV penetration. Range of capacity credits for APS and CA IOU process are based on different plant locations.

Fig. 3: Capacity credits applied by LSEs in planning studies

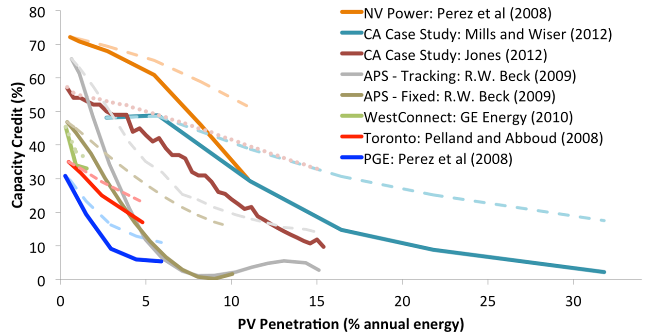


Fig. 4: PV capacity credit estimates with increasing penetration levels (dashed line is average capacity credit, solid line is incremental capacity credit)

Given the importance of solar's capacity credit for determining economic value and ensuring reliability, LSEs should consider conducting detailed estimates of solar capacity credit. LSEs considering portfolios with large amounts of solar may also need to account for expected changes in the solar capacity credit with increasing penetration.

6. EVALUATION OF THE ENERGY VALUE OF SOLAR USING PRODUCTION COST MODELS

In addition to capacity value, another primary driver of solar's economic value is the energy value. The energy value reflects the reduction in the PVRR from avoiding variable fuel and operational costs from conventional power plants in portfolios with solar. When LSEs evaluate candidate portfolios, they often use production cost models that account for the temporal variation in solar generation, demand, and other resource profiles. Many of the production cost models used by LSEs in planning studies have hourly temporal resolution (either over a one-week period each month or over the full year), and some production cost models account for the various operational constraints of conventional generation. These models appear to account for any benefit from solar generation being correlated with times when plants with high variable costs would otherwise be needed.

The LSEs in our sample that included CSP with thermal storage in candidate portfolios did not describe the approach they used to account for the dispatchability of CSP with thermal storage in the production cost models. In previous analyses, CSP with thermal storage was assumed to operate with a fixed generation profile in which the thermal storage generates as much power as possible in specific, static periods. While this simplified approach may capture some of the benefits of thermal storage, the full benefits to a particular LSE can be better captured by modeling the dispatchability of CSP directly in the production cost model. Compared to thermal storage, natural gas augmentation is relatively easier to model in a production cost model. One LSE described its approach to incorporating natural gas augmentation into its model.

The production cost models used by most LSEs also can account for changes in the energy value as the penetration of solar increases. One key factor in this regard is how LSEs consider the broader wholesale market and the assumptions they make about solar penetration in neighboring markets. If the LSE assumes other regions do not add solar, then selling power to the broader market during times of high insolation and low load may mitigate reductions in the energy value as the penetration of solar increases in the candidate portfolio. Such opportunities may not be available to the same degree, however, if many LSEs in a region simultaneously add solar. LSEs can improve their planning studies by better describing the assumptions and approaches used to account for broader wholesale markets when using production cost models to evaluate candidate portfolios.

7. ADJUSTING THE ENERGY VALUE TO ACCOUNT FOR INTEGRATION COSTS

Many LSEs adjust production cost model assumptions or results to account for solar integration costs. Adjustments make sense when there are factors that cannot be represented in the production cost model owing to data or computational limitations. In that case, the adjustments could be tailored to account for the shortcomings of a specific LSE's modeling approach or production cost model. Two studies accounted for solar integration costs by increasing the operating reserve requirement in the hourly production cost model to account for sub-hourly variability and uncertainty that otherwise would be ignored. The increase in operating reserves was based on a separate detailed analysis of sub-hourly variability and uncertainty of solar, wind, and load. Alternatively, other LSEs directly added an estimated integration cost to the production cost model results depending on the amount of solar included in the candidate portfolio (Table 3). The integration costs for solar added to the production cost model results ranged from \$2.5/MWh to \$10/MWh. Of the LSEs that used this approach, only one conducted a detailed study of solar integration costs (based on day-ahead forecast errors). The remaining LSEs relied on assumptions, results from studies in other regions, or integration cost estimates for wind. Based on the scarcity of detailed analysis of solar integration costs and the wide range of integration cost estimates used in the planning studies, more LSEs should consider carefully analyzing solar integration costs for their system (estimating what is not already captured by their modeling approach) to better justify their assumptions.

TABLE 3: ASSUMED INTEGRATION COSTS USED TO ADJUST PRODUCTION COSTS FOR PORTFOLIOS WITH SOLAR

Planning Studies	Integration Cost Added to Production Costs ($/MWh)		
	PV	CSP without thermal storage	CSP with thermal storage
PSCo	$5.15	N/A	$0
APS	$2.5	$0	$0
TEP	$4	$2	$0
Tri-State	$5–$10	N/A	$5–$10
PGE	$6.35	N/A	N/A
NPCC	$8.85–$10.9	N/A	$0

8. ADDITIONAL FACTORS INCLUDED OR EXCLUDED FROM PLANNING STUDIES

Aside from the capacity and energy values, other attributes of solar are often also included in planning studies. The potential risk-reduction benefit of solar, for example, can be accounted for in studies that evaluate the performance of candidate portfolios with and without solar under different assumptions about the future. Transmission and distribution benefits, or costs, related to solar are not often accounted for in LSE studies. In one clear exception, avoided distribution costs were directly accounted for by one LSE in portfolios with distributed PV. In a few other cases, candidate portfolios with solar required less transmission than candidate portfolios with other generation options. The difference in avoided costs between utility-scale solar and distributed PV are not well known, but as more studies provide insight into these differences, LSEs should consider incorporating that information into their planning studies.

A number of LSE planning studies included options that may increase the economic value of solar. Some LSEs included thermal storage or natural gas augmentation with CSP plants, one study considered PV coupled with a lead-acid battery, and another added grid-scale batteries to candidate portfolios with wind and solar (in both cases the additional capital cost of the batteries was too high to reduce the overall PVRR relative to the cases without batteries). Other studies considered a wide range of grid-level storage options without explicitly tying these storage resources to the candidate portfolios with wind or solar. None of the studies appeared to directly consider the role of demand response in increasing the value of solar or directly identify synergies in the capacity credit or integration costs for combinations of wind and solar. Any such synergy in energy value, on the other hand, may have been indirectly accounted for in production cost modeling of candidate portfolios with combinations of wind and solar.

9. DESIGNING CANDIDATE PORTFOLIOS TO USE IN PLANNING STUDIES

While the overall framework used by many of the LSEs for evaluating candidate portfolios appears to capture many (but not all) solar benefits, one important area for improvement is creating candidate portfolios in the first place. The complex interactions between various resource options and existing generation make it difficult to identify which resource options will be most economically attractive. To manage this complexity, a number of LSEs relied on capacity-expansion models to design candidate portfolios, most of which were based on deterministic assumptions about future costs and needs (Table 4). The LSEs that did not use capacity-expansion models either manually created candidate portfolios based on engineering judgment or stakeholder input or created candidate portfolios by ranking resource options using simplified criteria.

TABLE 4: CAPACITY-EXPANSION MODELS USED BY LSE'S CONSIDERING SOLAR

LSE/planning entity	Capacity-expansion model
Duke Energy	System Optimizer, Ventyx
El Paso	Strategist, Ventyx
NPCC	Regional Portfolio Model
PacifiCorp	System Optimizer, Ventyx
PNM	Strategist, Ventyx
PSCo	Strategist, Ventyx
TEP	Capacity Expansion, Ventyx
Tri-State	System Optimizer, Ventyx

A logical way to rank resources is to estimate the change in the PVRR of a portfolio from including a particular resource in the portfolio and displacing other resources. This change in PVRR is called the "net cost" of a resource since it represents the difference between the cost of adding the resource and the avoided cost from displacing other resources that are no longer needed to ensure the portfolio can meet reliability and regulatory constraints. Since the goal of many planning studies is to minimize the expected PVRR, the resources with the lowest net cost should be added to the portfolio. LSEs in California used a similar approach to identify renewable resource options that were included in their candidate portfolios.

In contrast, a number of LSEs used the levelized cost of energy of resource options along with various adjustments (often based on capacity and integration cost adjustments) to rank resource options. The adjustments, particularly the capacity adjustments, were often not clearly justified and did not always link back to the broader objective of minimizing the expected PVRR. Based on these findings, we recommend that, where possible, LSEs use capacity-expansion models to build candidate portfolios. Improvements in capacity expansion models to account for factors like risk, uncertainty, dispatchability of CSP plants with thermal storage, and operational constraints for conventional generation may be appropriate for some LSEs. If using a capacity-expansion model to build candidate portfolios is not possible, then an approach like the net cost ranking should be considered instead.

10. ECONOMIC EVALUATION OF BIDS IN PROCUREMENT PROCESSES

Finally, we found that LSE procurement often evaluated the economic attractiveness of bids based on the estimated net cost, but often it was unclear exactly how this net cost was evaluated. The lack of clarity in many procurement documents makes it difficult for a bidder to estimate how various choices it makes in terms of solar technology or configuration will impact the net cost of its bid. The bidder will know how these choices affect the cost side of the bid but often must guess or try to replicate the LSE's planning process to determine how different choices will affect the LSE's avoided costs. LSEs likely could elicit more economically attractive bids by providing as much detail as possible on how the net cost of each bid will be evaluated and the differences in the LSE's avoided costs for different technologies and configurations.

Although this review focused on the valuation of solar in planning and procurement, many of the LSEs are considering other renewable technologies, particularly wind. The lessons learned from this analysis and many of the recommendations apply to the evaluation of other renewable energy options beyond solar.

ACKNOWLEDGEMENTS

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ACRONYMS AND ABBREVIATIONS

APS	Arizona Public Service
CA IOU	California Investor-Owned Utility
CSP	Concentrating solar power
CT	Combustion turbine
IID	Imperial Irrigation District
IRP	Integrated resource plan
LADWP	Los Angeles Department of Water and Power
LOLP	Loss of load probability
LSE	Load-serving entity

NPCC	Northwest Power and Conservation Council
PGE	Portland General Electric
PNM	Public Service of New Mexico
PSCo	Public Service of Colorado
PV	Photovoltaics
PVRR	Present value of the revenue requirement
RPS	Renewables portfolio standard
T&D	Transmission and distribution
TEP	Tucson Electric Power

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December 14, 2015

An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes

Andrew Mills

Lawrence Berkeley National Laboratory

Oregon Public Utilities Commission

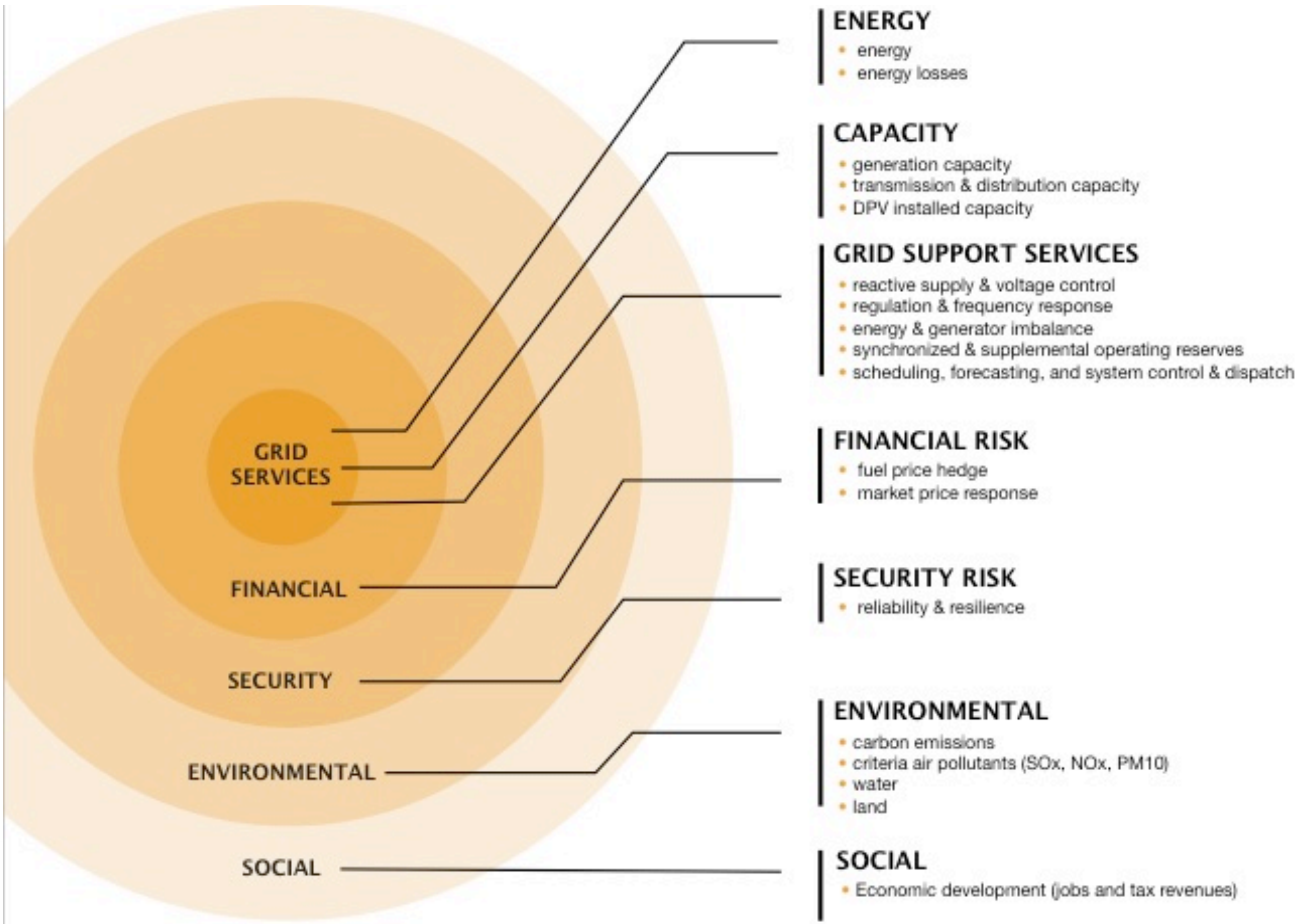
August 17, 2015

The work described in this presentation was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy and Office of Electricity Delivery and Energy Reliability

BERKELEY LAB

ENERGY TECHNOLOGIES AREA

Value categories from RMI review of PV benefit and cost studies



Motivation and scope

- **Motivations:**
  - As the cost of solar generation falls, solar is being considered as one of many viable options for supplying electricity
  - Recognizing and evaluating the economic value of solar will become progressively important for justifying its expanded use
- **Objectives:**
  - Analyze the treatment of solar in current planning studies and procurement processes from U.S. load-serving entities (LSEs)
  - Compare approaches across LSEs and to methods identified in broader literature on solar valuation, including LBNL research
- **Intended Audiences:**
  - LSE planners and their regulators, stakeholders in public planning and procurement processes, renewable developers

Approach

- Review 16 planning studies and nine documents describing procurement processes
- All created during 2008–2012 by LSEs interested in solar power
- Identify how current practices reflect the drivers of solar's economic value with a focus on:
    - Treatment of the capacity value, energy value, and integration costs of solar energy
    - Treatment of other factors including the risk reduction value of solar and impacts to T&D
    - Methods used to design candidate portfolios of resources for evaluation within the studies
    - Approaches used to evaluate the economic attractiveness of bids during procurement

Studies included in sample

Load-serving entity or study author	Planning study (year)	Procurement practices (year)
Arizona Public Service	2012	2011
California IOU Process	2010	2011
Duke Energy Carolinas	2011	-
El Paso Electric	2012	2011
Idaho Power	2011	-
Imperial Irrigation District	2010	-
Los Angeles Department of Water and Power	2011	2012
Northwest Power and Conservation Council	2010	-
NV Energy	2012	2010
PacifiCorp	2011	2010
Portland General Electric	2009	2012
Public Service of Colorado	2011	2011
Public Service of New Mexico	2011	2011
Salt River Project	2010	-
Tri-State Generation and Transmission	2010	-
Tucson Electric Power	2012	-

Sample primarily includes LSEs in the western United States that are considering solar power, among other options

General planning process adopted by many LSEs followed similar pattern

Steps 2 and 3 are the most important for capturing the economic value of solar, and are largely the focus of this review

1: Assessment of future needs and resources

2: Creation of feasible candidate portfolios that satisfy needs

3: Evaluation of candidate portfolio costs and impacts

4: Selection of preferred portfolio

5: Procurement of resources identified in preferred portfolio

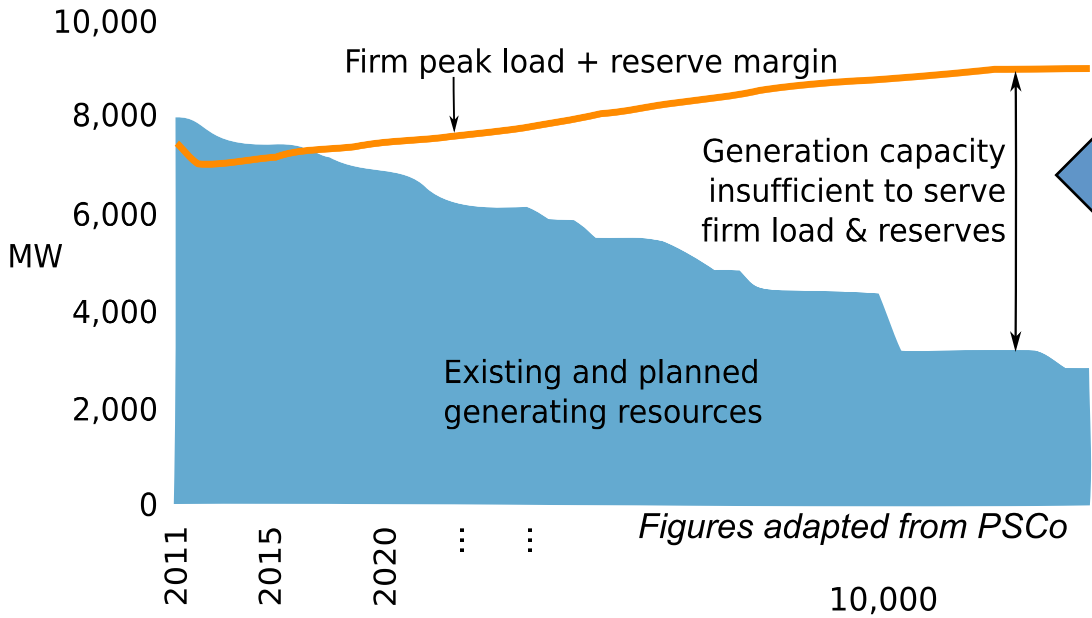
Not all LSEs exactly followed these steps: depending on the plan, some steps were not included, multiple steps were bundled into one step, or the order of steps did not follow this same pattern

Solar technologies included in assessment of potential future resources

Solar technology category	Variation	Integrated thermal storage	Natural gas firing in boiler
Photovoltaic	Fixed	N/A	N/A
	Single-axis tracking	N/A	N/A
	With lead acid battery	N/A	N/A
Concentrating solar power	Parabolic trough	None	No
	Parabolic trough	None	Yes
	Parabolic trough	3 hours	No
	Parabolic trough	6-8 hours	No
	Solar power tower	7 hours	No
	Solar chimney (or solar updraft tower)	None	No
Solar thermal gas hybrid plants (or integrated solar combined cycle, ISCC)		N/A	N/A

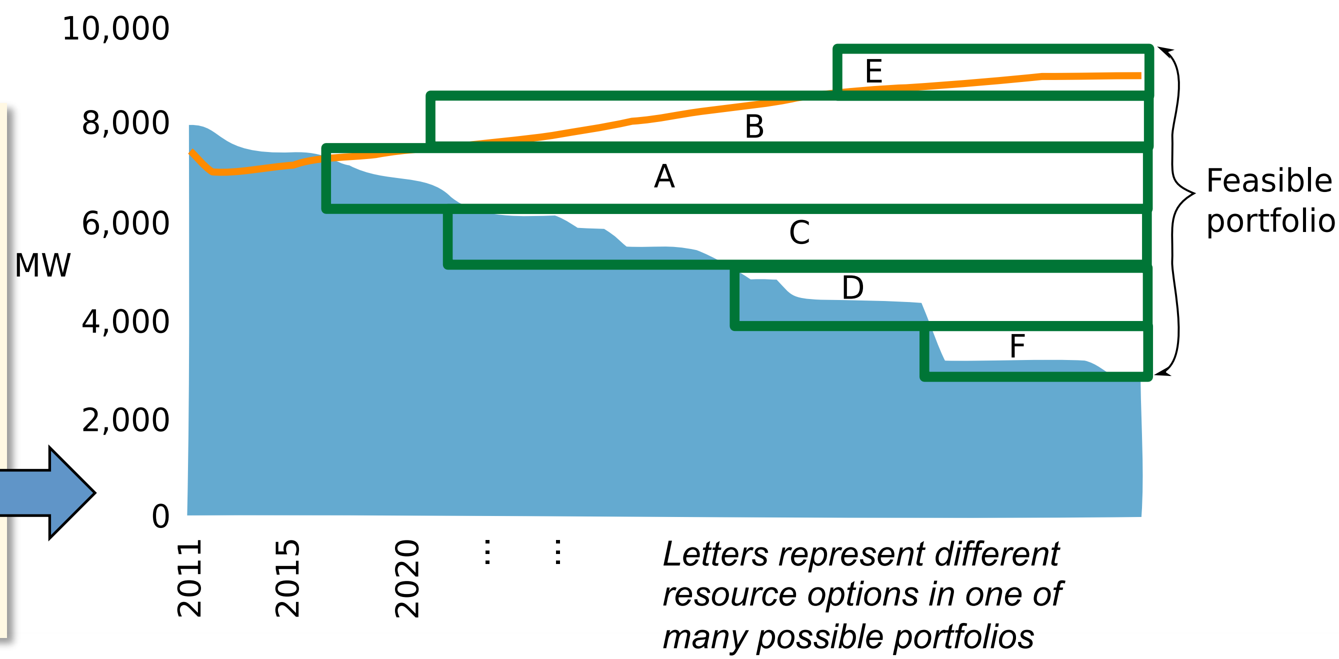
Flat-panel PV (fixed and tracking), parabolic-trough and power-tower CSP with or without thermal storage or natural gas augmentation are mature enough for commercially application. Other technologies, like solar chimney, are still in pilot or early-demonstration stage.

Creation of feasible candidate portfolios implicitly provides solar's capacity value

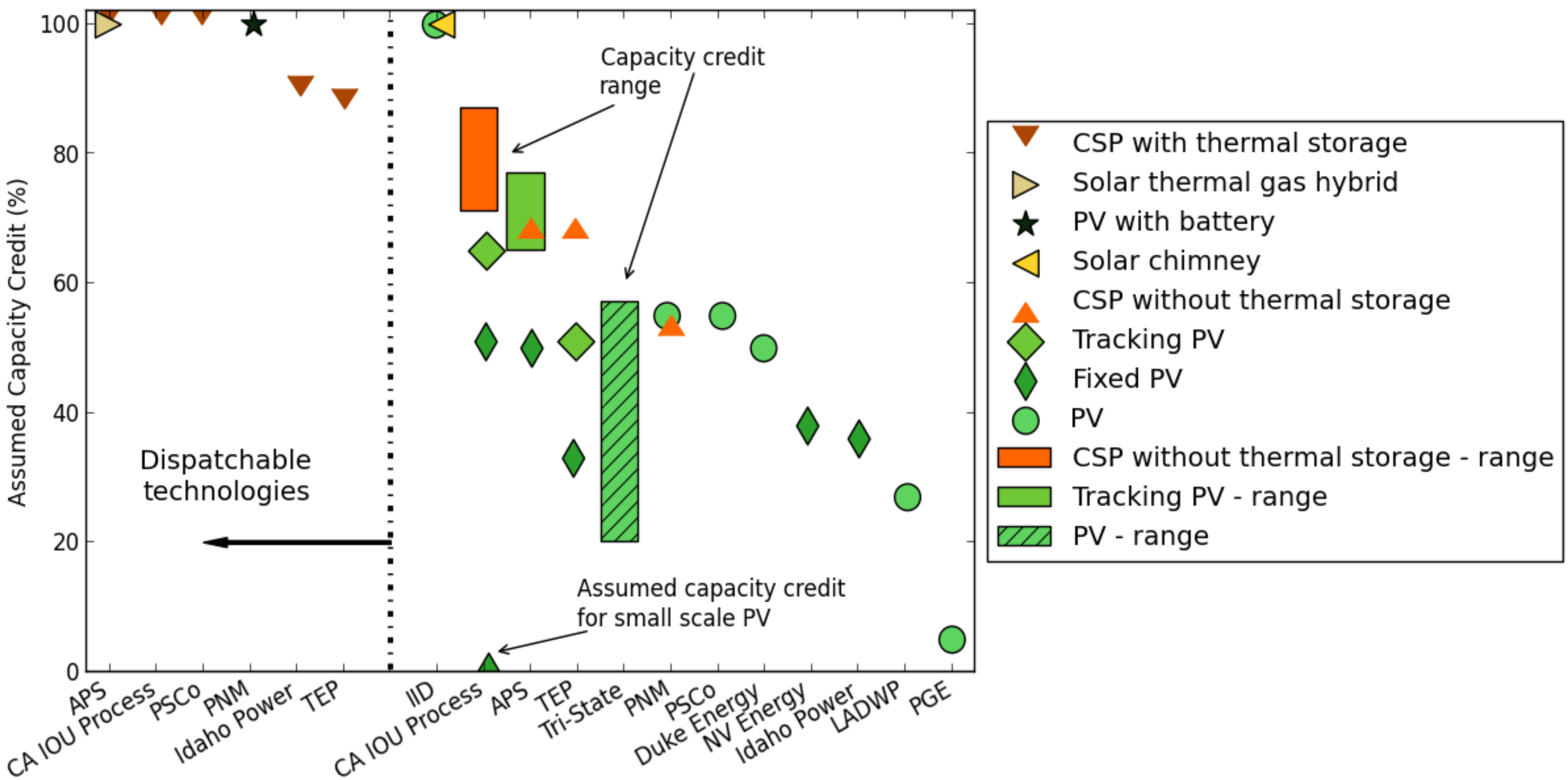


In almost all planning studies, the amount of resources added to each portfolio (including solar) was sufficient to meet forecasted peak load and planning reserve margin over the planning horizon

As a result, adding solar to a candidate portfolio reduced the need for some other capacity resource (often CTs or CCGTs) to meet the peak load and planning reserve margin



Solar capacity value (in economic terms) depends on assumed capacity credit



Capacity credit used by utilities in planning studies covers a wide range depending on technology, utility, and tools used by utilities to estimate capacity credit.

Capacity credits were rarely estimated using detailed LOLP studies (only PSCo and APS). More often they were based on solar production during peak load periods or rules of thumb.

Methods to calculate capacity credit used in planning studies

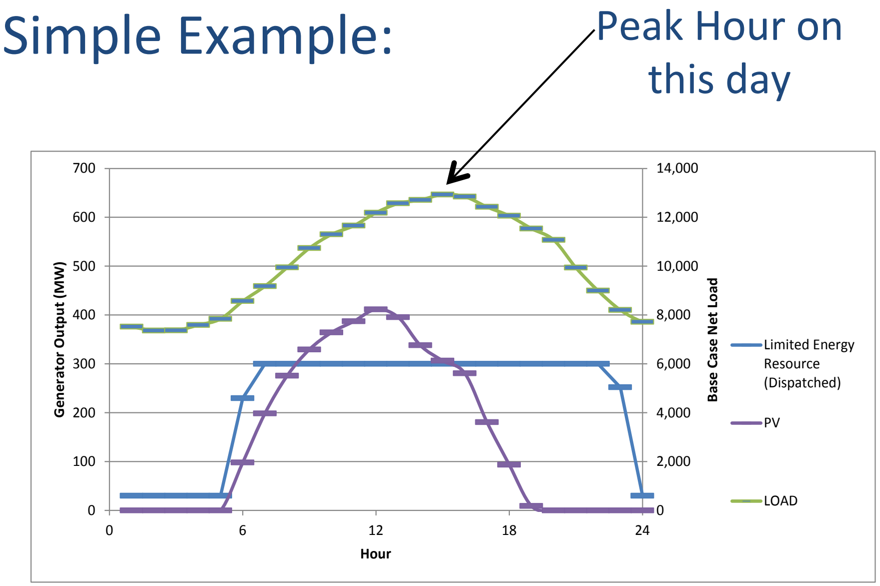
Name	Description	Examples
Full Effective load-carrying capacity (ELCC) calculation	Perform full ELCC calculation using iterative LOLPs in each period	APS, PSCo
Capacity factor approximation	Examines output during periods of highest demand	PNM, TEP, CA IOU's, NV Energy, Idaho Power, Tri-State
Engineering Judgment	Assumptions based on key drivers of capacity credit	PGE: Assume low capacity credit for solar since peak load during winter nights
Capacity factor approximation using loss of load probability (LOLP)	Examines output during periods of highest LOLP	-
Effective load-carrying capacity (ELCC) approximation (Garver's Method)	Calculates an approximate ELCC using LOLPs in each period	-

Capacity factor approximation methods

Basic Method:

- Examine generator output/ capacity factor during periods of high net load or periods of highest risk
- Choice of peak period (top 100 hours, top 1% etc) can significantly influence results

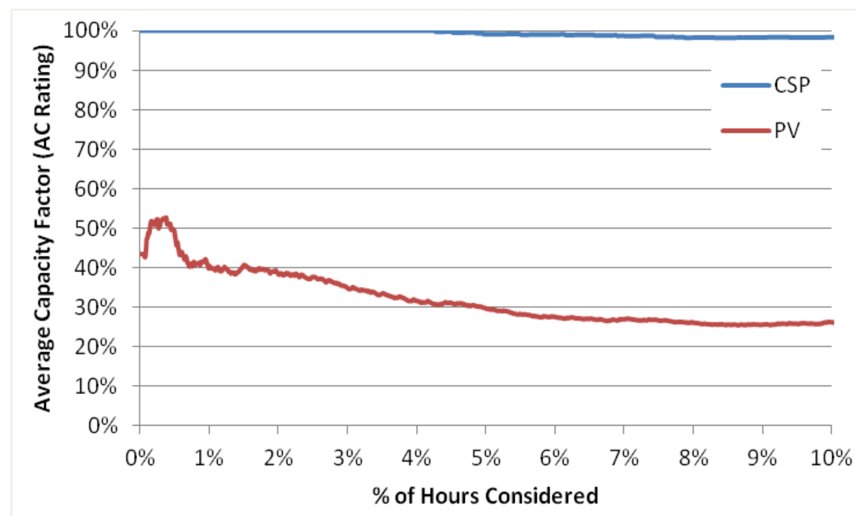
Simple Example:



Pros/Cons

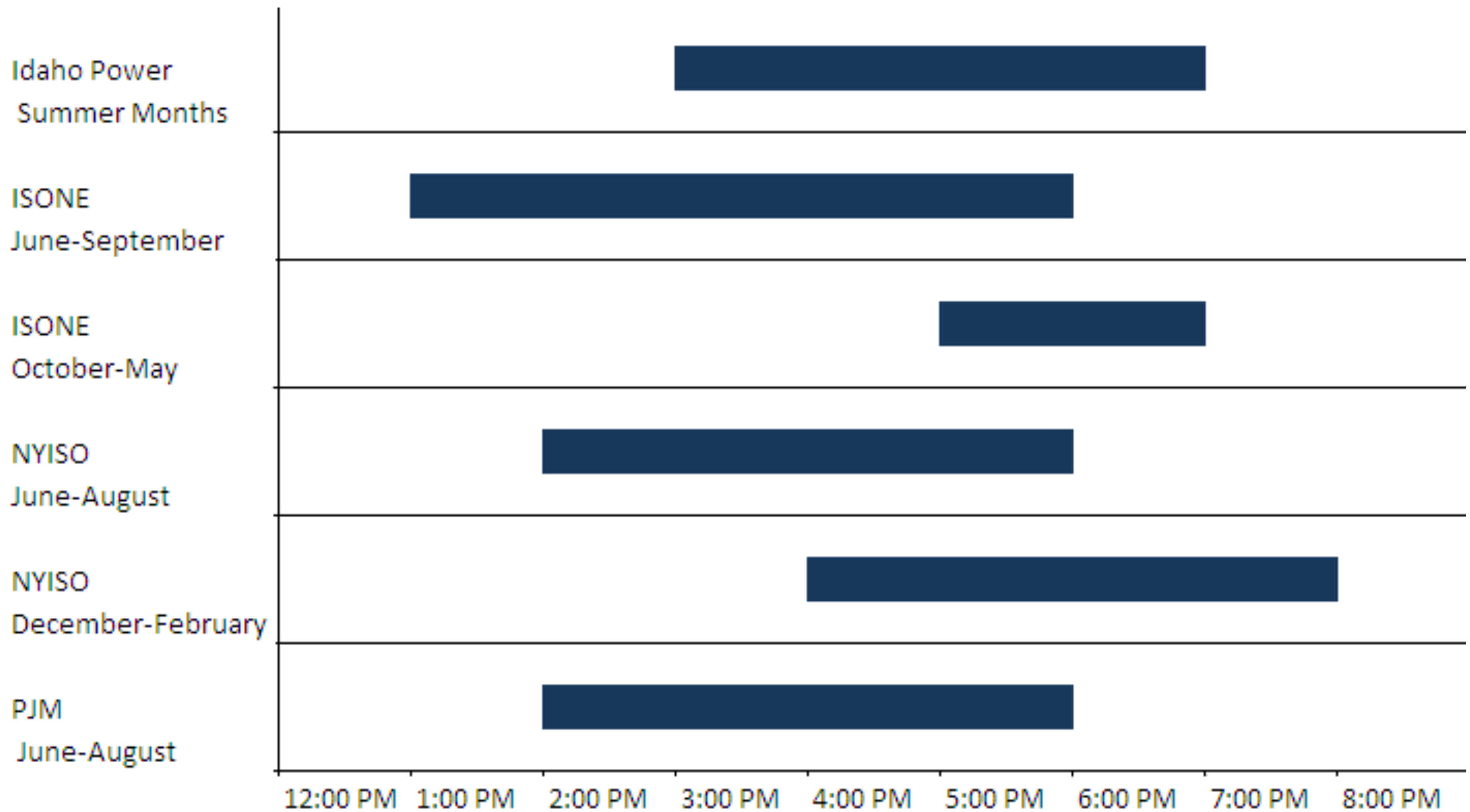
- Very easy, useful for rough estimates
- Requirements are only load, solar profiles and a spreadsheet
- Still somewhat common although decreasingly so…

But period examined is important:



Source: Denholm presentation at DER Valuation Workshop

Examples of peak periods used in capacity factor approximation methods in the US



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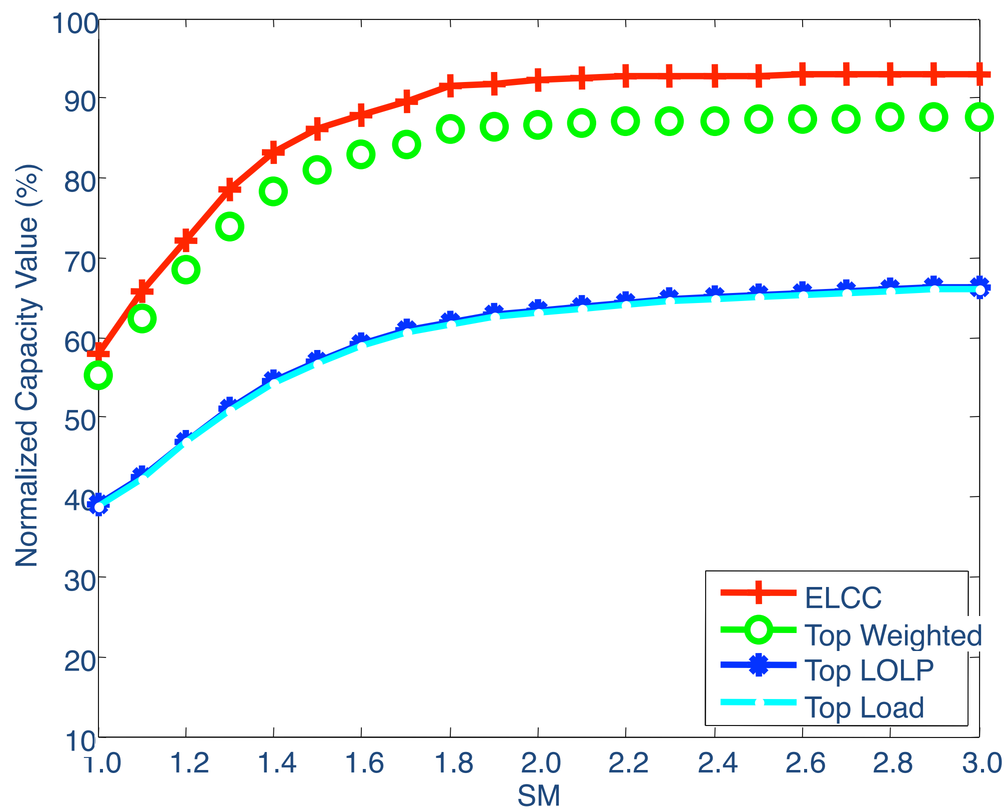
Capacity factor approximation methods may not fully measure contribution to resource adequacy

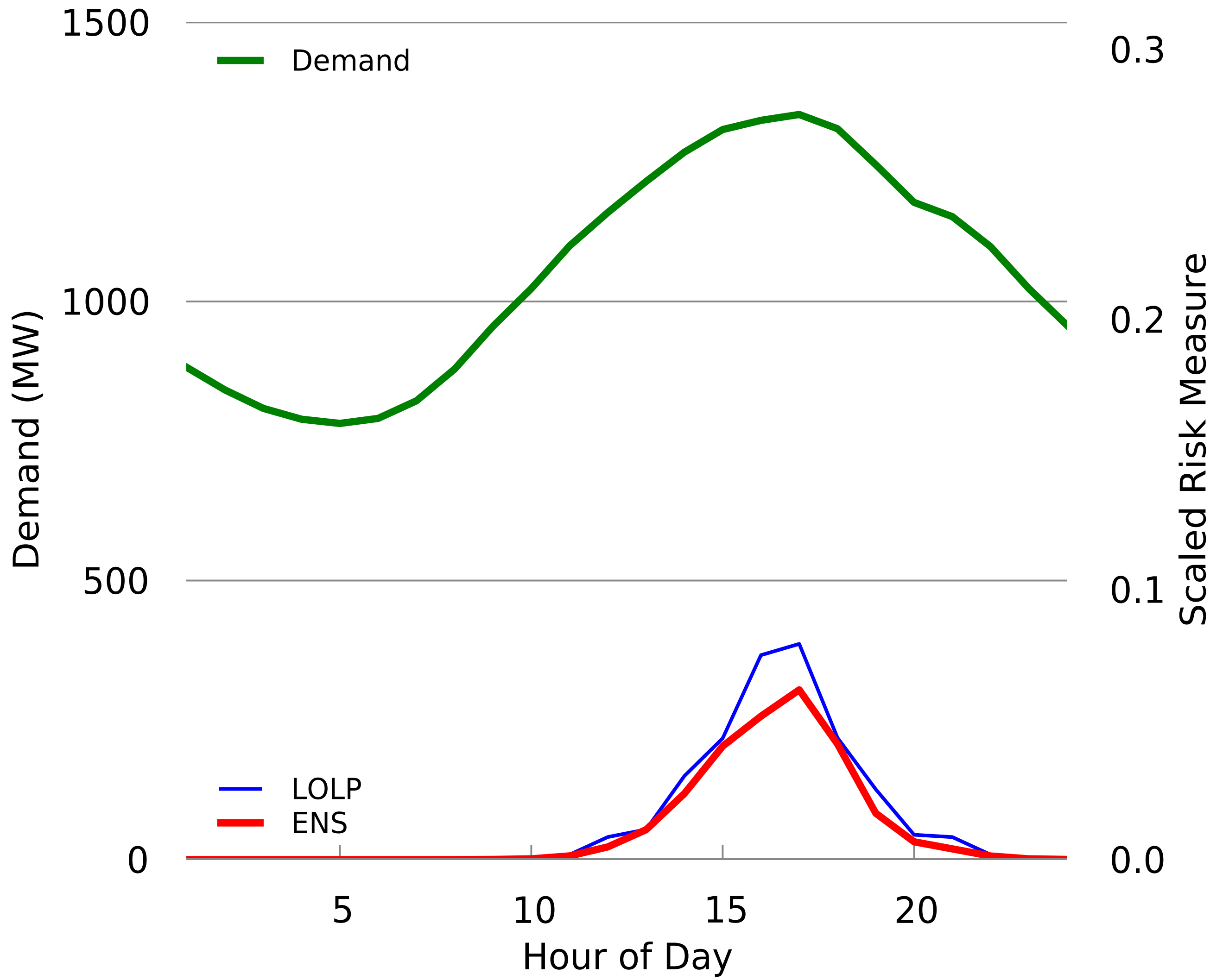
- Solar generation-load relationship is only part of the equation
- Capacity factor, even during peak periods, won't capture annual risk profile
- Improvement is to use CF during period of high risk (high LOLP periods)
- All CF based approaches are inherently limited

Comparison of Capacity Factor Methods for CSP with Increasing Levels of Storage

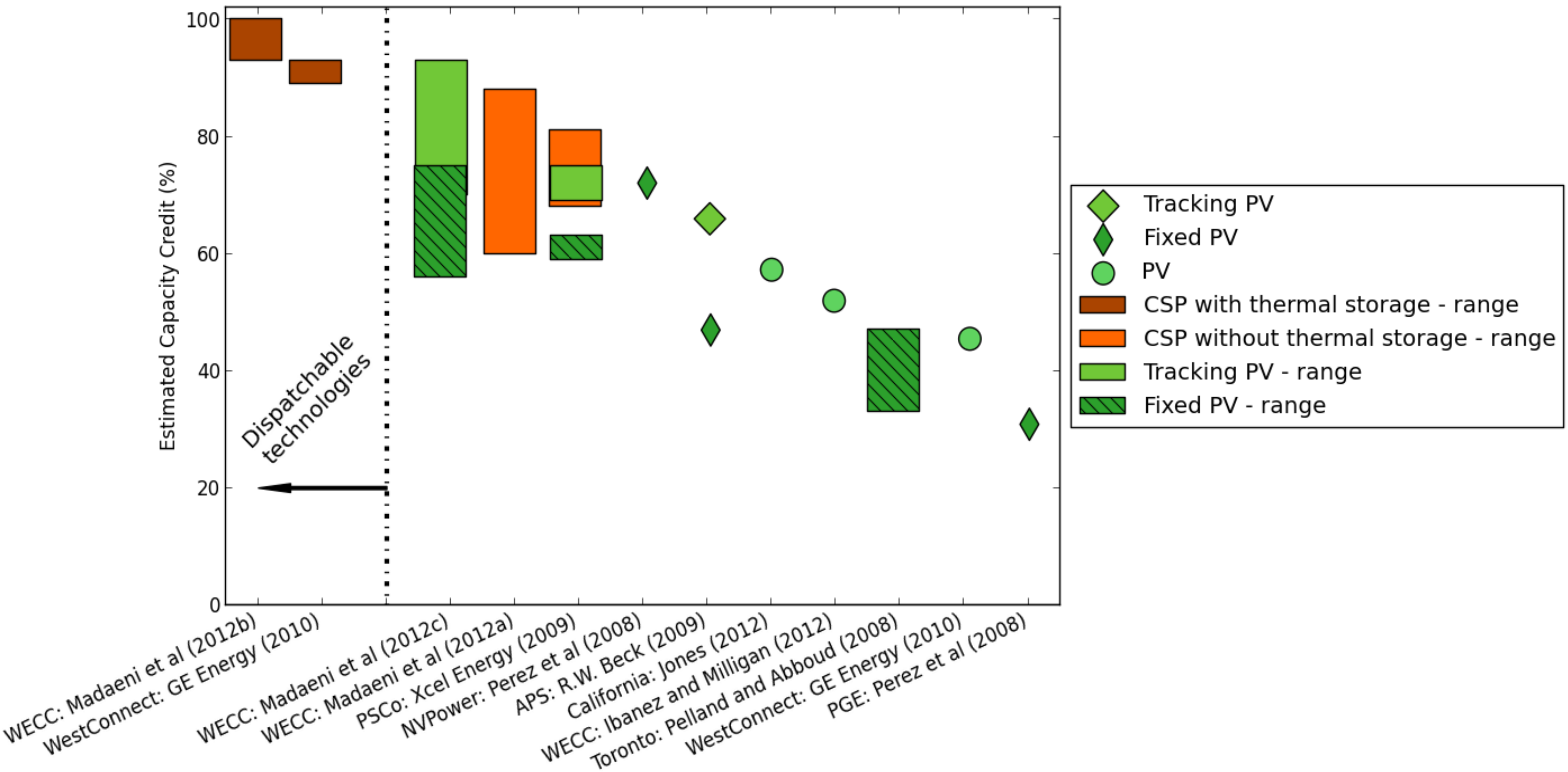


Source: Denholm presentation at DER Valuation Workshop

Loss of Load Probability (LOLP) is not equal among peak load hours

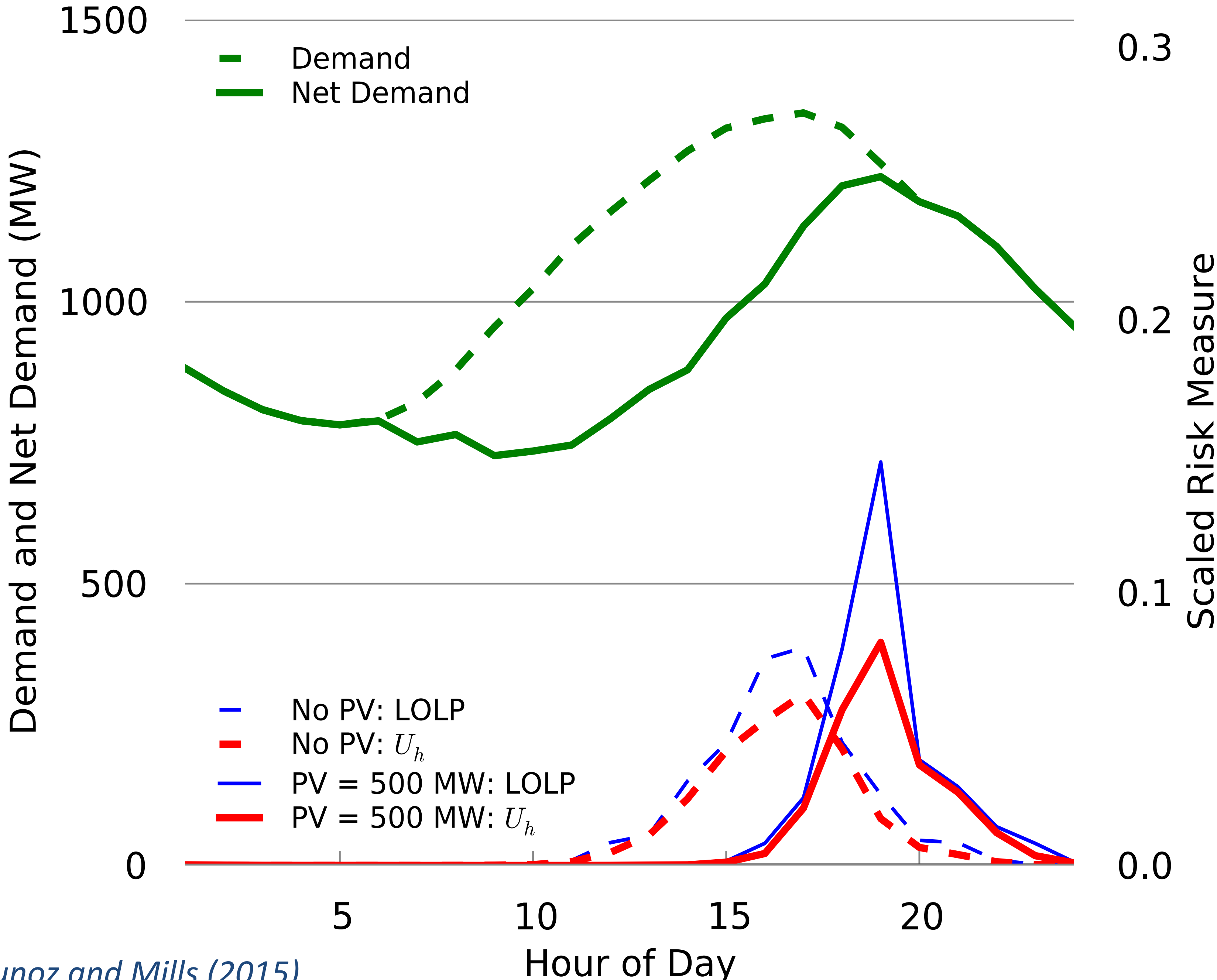


Estimates of capacity credit at low solar penetration from LOLP-based studies



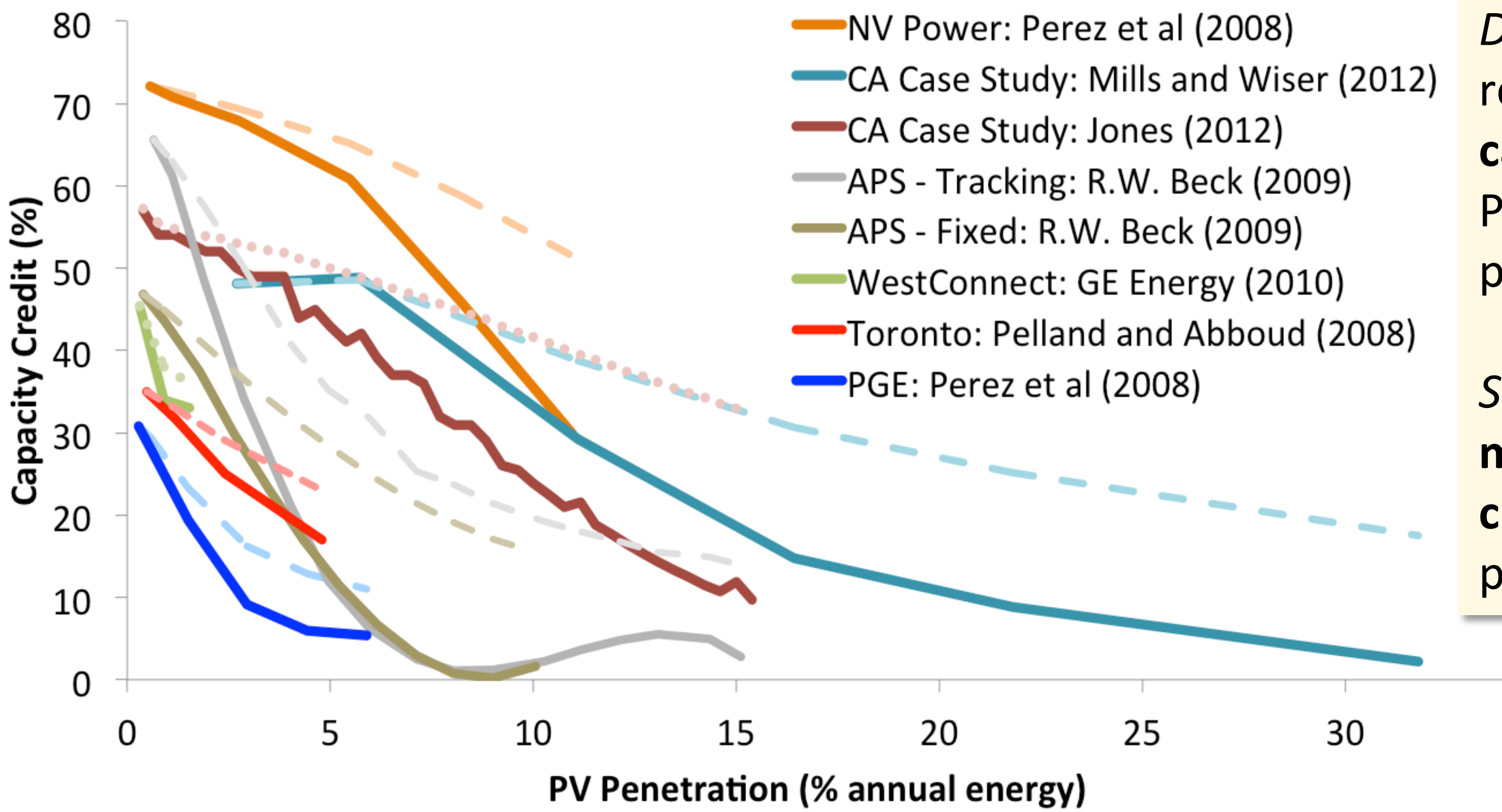
The range of capacity credits used by LSEs in planning studies largely falls within the range reported in the broader literature for low-penetration PV and CSP

Solar capacity value depends on penetration level



Source: Munoz and Mills (2015)

Broader literature indicates capacity credit of PV declines with penetration



Dotted lines represent **average capacity credit** for all PV up to that penetration level

Solid lines represent **marginal capacity credit** at a particular penetration level

While a number of LSEs are aware that the capacity credit can decrease with increasing penetration, only APS appeared to account for this in its planning study.

Planning studies should consider improving estimates of solar capacity credit.

Evaluation of the energy value of solar using production cost models

- Some form of production cost models were used to simulate dispatch of power plants and estimate variable costs
- Correlations between solar generation and times when the fuel costs of conventional power plants are high should be reflected in most studies
  - Any change in energy value due to increasing solar displacing resources with lower and lower variable costs should also be reflected in most studies
  - Not all production cost models included unit-by-unit operational constraints for conventional generation
- Planning studies provide little detail on how thermal energy storage dispatchability is captured in production cost models

Partial list of production cost models used:

- AURORAxmp (EPIS)
- PLEXOS (Energy Exemplar)
- PROMOD IV (Ventyx)
- PROSYM (Ventyx)
- PROVIEW (Ventyx)

Adjustments to the energy value to account for integration costs

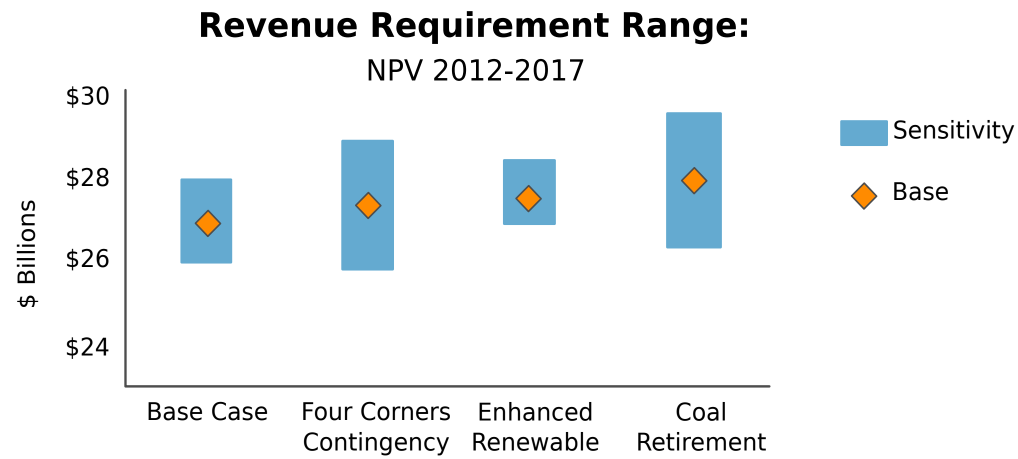
Some LSEs (NV Energy and CA IOU Process) increased ancillary service requirements in production cost models to account for short-term variability and uncertainty of solar. Integration costs due to ancillary services were then embedded in evaluation of portfolio with solar.

Others added estimated integration costs to production cost results (below). Few studies were used to estimate these integration costs for solar.

Planning Studies	Integration Cost Added to Production Costs ($/MWh)			Notes
	PV	CSP without thermal storage	CSP with thermal storage	
PSCo	$5.15	N/A	$0	
APS	$2.5	$0	$0	
TEP	$4	$2	$0	
Tri-State	$5–$10	N/A	$5–$10	Most scenarios used low end of costs; scenarios with more renewables used higher costs
PGE	$6.35	N/A	N/A	
NPCC	$8.85–$10.9	N/A	$0	Integration costs assumed to escalate up to 2024

Additional factors included or excluded from planning studies

- The risk-reduction benefits of solar can be included in LSE studies by accounting for uncertainty in future parameters when evaluating candidate portfolios



- Distributed PV and utility-scale PV, and their respective benefits and costs, were not separately considered by most LSEs
  - A few LSEs, however, adjusted portfolio costs to account for the presumed benefits of distributed PV
  - In one case, the benefit of distributed PV varied by location but was most often around $5/MWh (with a range of $4.3 to $26.2/MWh)
- Options that might mitigate output variability and uncertainty of solar were included in some studies, examples include:
  - Thermal storage and natural gas augmentation on CSP plants, batteries coupled to a PV system, and bulk power storage as a resource option

Economic evaluation of bids in procurement processes

- LSE procurement often evaluated the economic attractiveness of bids based on the estimated net cost, but often it was unclear exactly how this net cost was evaluated

- The lack of clarity in many procurement documents makes it difficult for a bidder to estimate how various choices it makes in terms of solar technology or configuration will impact the net cost of its bid

- The bidder will know how these choices affect the cost side of the bid but often must guess or try to replicate the LSE's planning process to determine how different choices will affect the LSE's avoided costs

- LSEs likely could elicit more economically attractive bids by providing as much detail as possible on how the net cost of each bid will be evaluated and the differences in the LSE's avoided costs for different technologies and configurations

Conclusions

- Full evaluation of the costs & benefits of solar requires that a variety of solar options are included in diverse set of candidate portfolios
- Design of candidate portfolios, particularly regarding the methods used to rank potential resource options, can be improved
- Studies account for the capacity value of solar, though capacity credit estimates with increasing penetration can be improved
- Most LSEs have the right approach and tools to evaluate the energy value of solar. Improvements remain possible, particularly in estimating solar integration costs used to adjust energy value
- T&D benefits, or costs, related to solar are rarely included in studies
- Few LSE planning studies can reflect the full range of potential benefits from adding thermal storage and/or natural gas augmentation to CSP plants
- The level of detail provided in RFPs is not always sufficient for bidders to identify most valuable technology or configurations

For More Information

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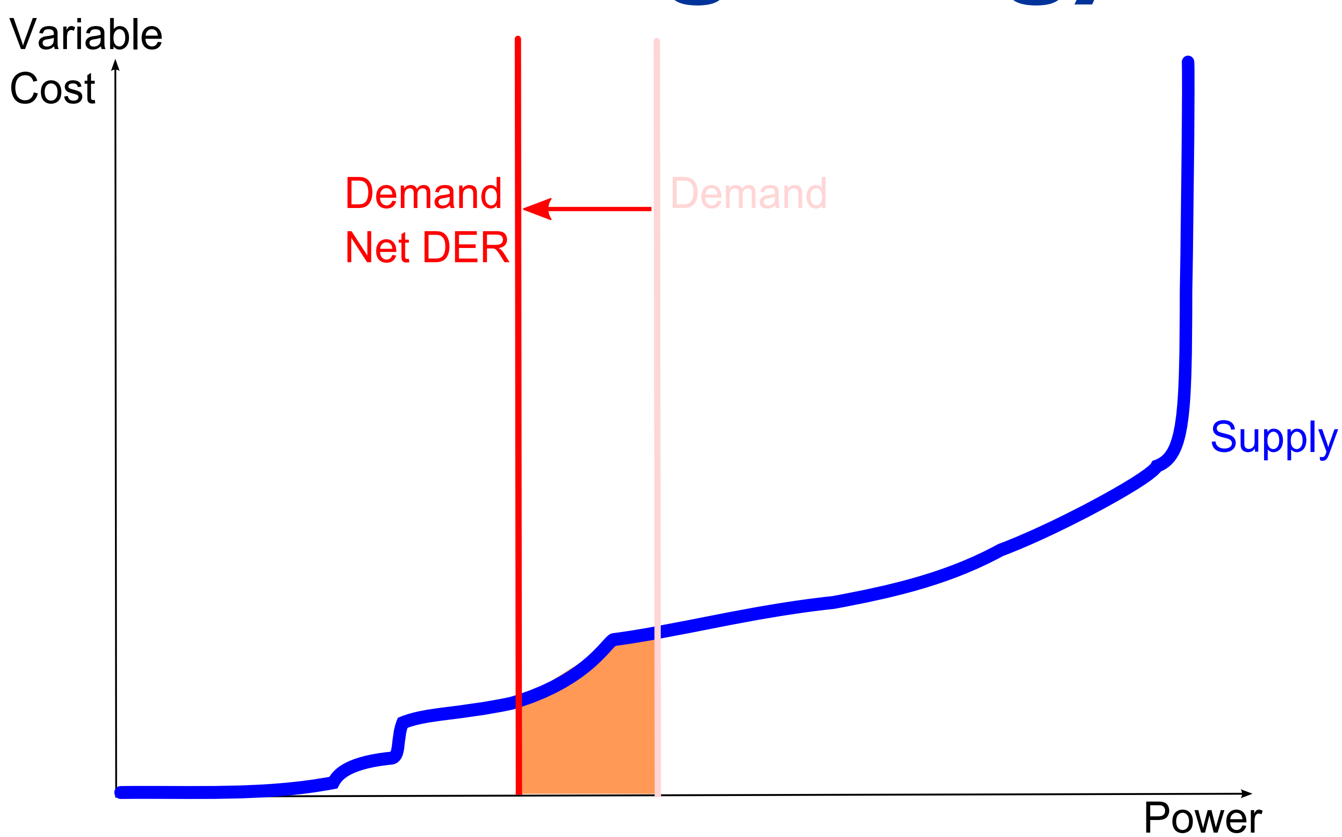
The work described in this presentation was funded by the U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy (Solar Energy Technologies Program) and Office of Electricity Delivery and Energy Reliability (National Electricity Division) under Contract No. DE-AC02-05CH11231.

Download all of the original presentations from the U.S. DOE workshop on valuing DER: http://energy.gov/oe/downloads/estimating-benefits-and-costs-distributed-energy-technologies-workshop-agenda-and

Mills, A.D., and R.H. Wiser. 2012. "An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes." LBNL-5933E. Berkeley, CA: Lawrence Berkeley National Laboratory. emp.lbl.gov/sites/all/files/lbnl-5933e_0.pdf.

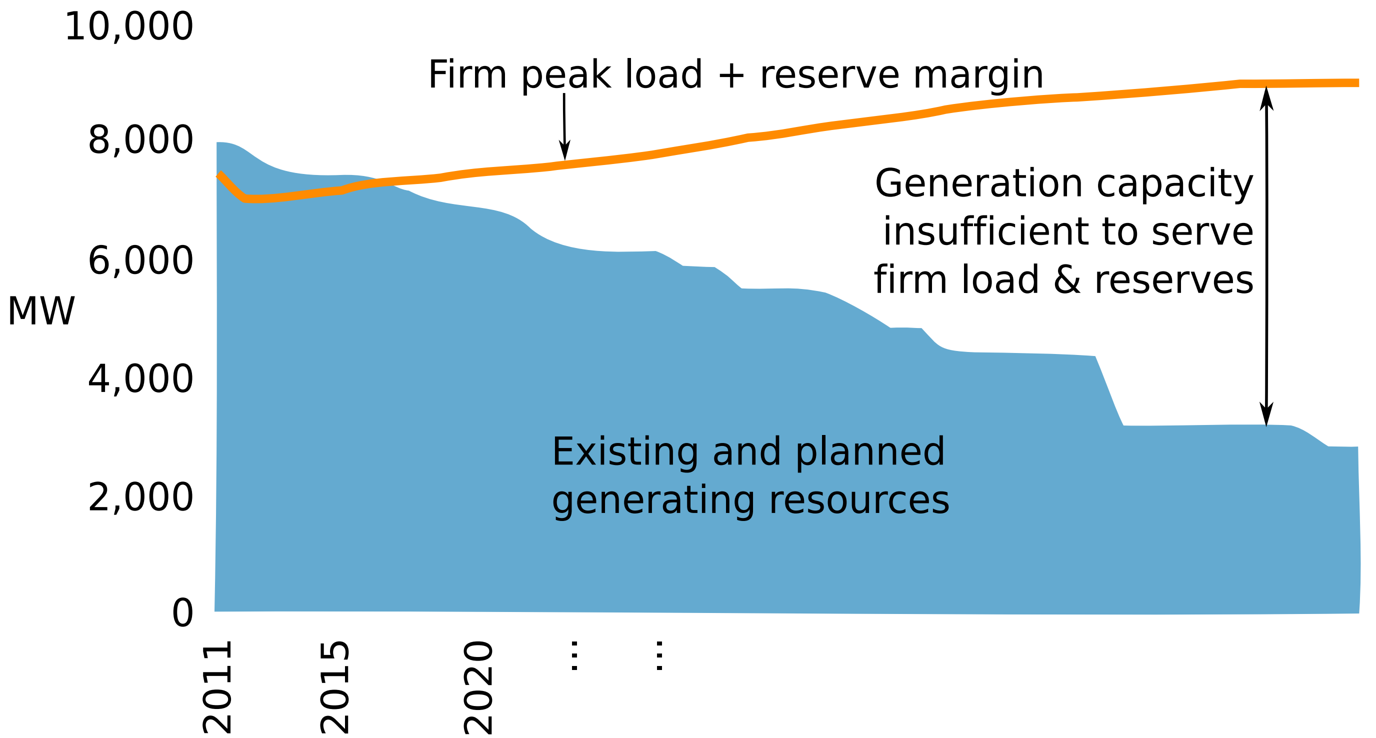
Munoz, F.D., and A.D. Mills. 2015. "Endogenous Assessment of the Capacity Value of Solar PV in Generation Investment Planning Studies." *IEEE Transactions on Sustainable Energy, in press,* doi:10.1109/TSTE.2015.2456019.

Understanding energy value



- Power systems are generally dispatched to minimize variable costs
- Dispatch plants up to the point that demand is met (marginal unit)
- Addition of DER reduces generation, which reduces variable costs
- With large DER share, increasingly lower cost units are displaced
- Complications: (1) some DERs shift electricity use (DR), or increase it (storage, EVs); (2) power system constraints can lead to curtailment

Understanding capacity value

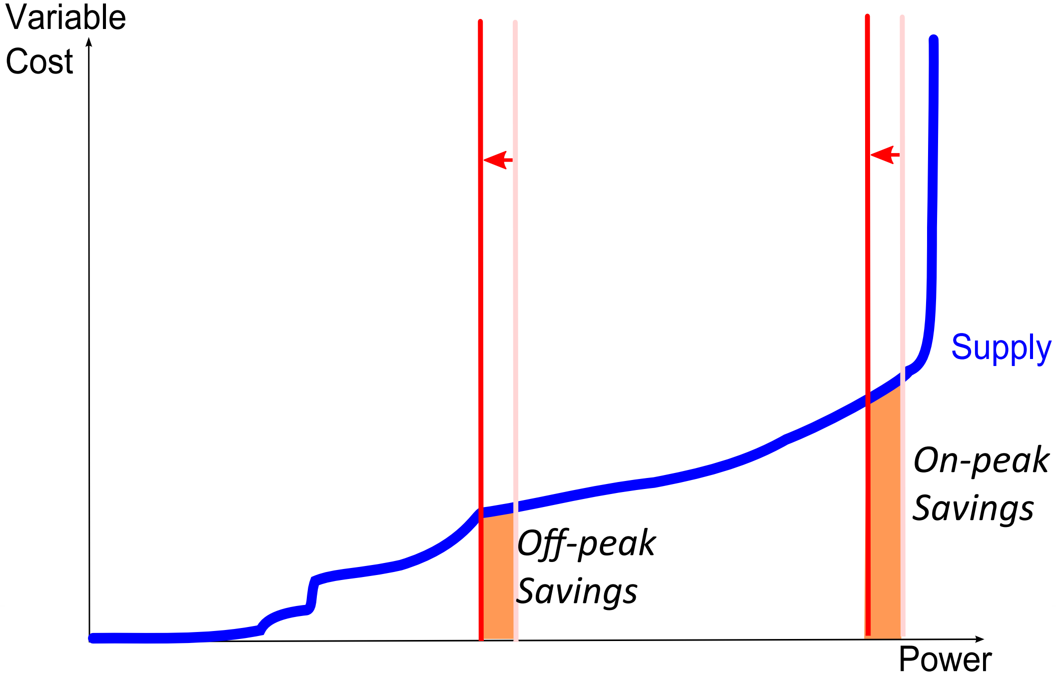


- Power systems require sufficient generation capacity to reliably meet demand
- New capacity is added as load grows, old units retire, or contracts expire
- DER contributes to adequacy, reducing the need to build other units
- With large DER share, incremental contribution to adequacy can decline
- Complications: (1) Standard methods are not well suited to energy-limited resources (e.g. storage, EVs) (2) Deliverability is important consideration for DER

Methods to calculate energy value

Three main questions / steps:

1. When is DER generating (or charging)?
2. What generation is displaced (or used) during those times (i.e. what is the marginal unit)?
   - Can all DER generation be used or is there a need for some curtailment?
3. What are the variable costs of the displaced generators?



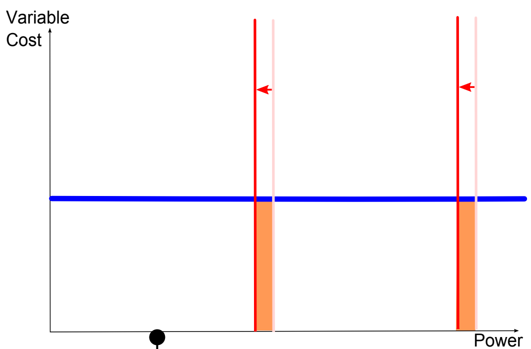
Energy Value of DPV from RMI Study:

Step #1: When is DER generating (or charging)?

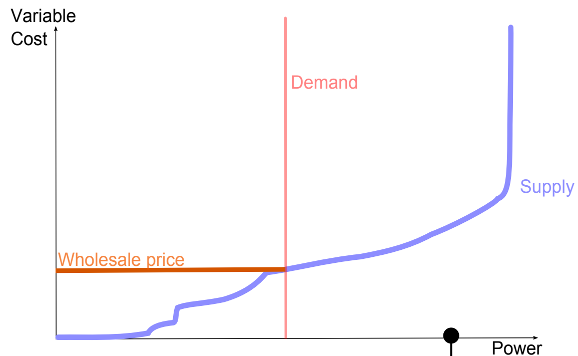
- Solar PV or distributed wind
  - Relatively straightforward to use historical meteorological data with location, type, size, and orientation of DER
- Demand response
  - Programs often designed to reduce demand during peak times
  - Does customer time-shift energy consumption (e.g. pre-cooling)? Is there a rebound (increase in energy post-event)?
- Electric vehicles
  - Customer preferences & infrastructure will dictate charging needs/availability
- Customer-sited storage
  - Is storage dispatched based on local retail rates?
  - Or is it dispatched based on local T&D needs?
  - Or is it dispatched based on bulk power system needs?
- Combined heat and power (CHP)
  - What processes drive dispatch of CHP units? Is it building/district heating? Industrial process? Do bulk power system needs impact dispatch?

Step #2: What generation is displaced (or used) and at what heat rate?

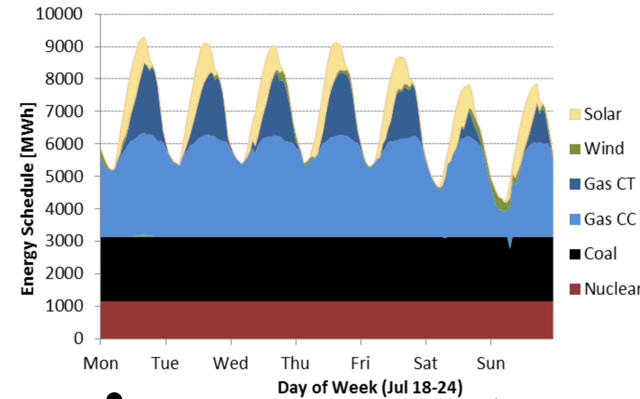
One type of unit always on the margin

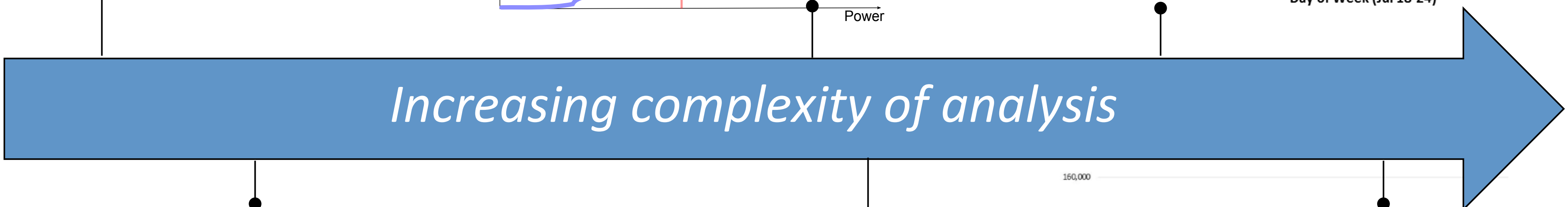


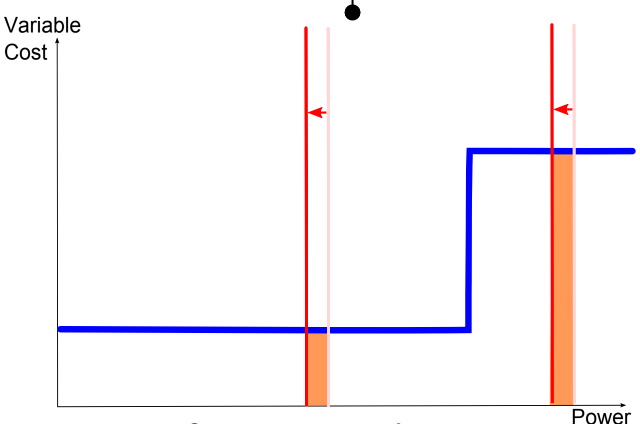
Historical marginal plant: wholesale prices, system lambdas, econometric methods



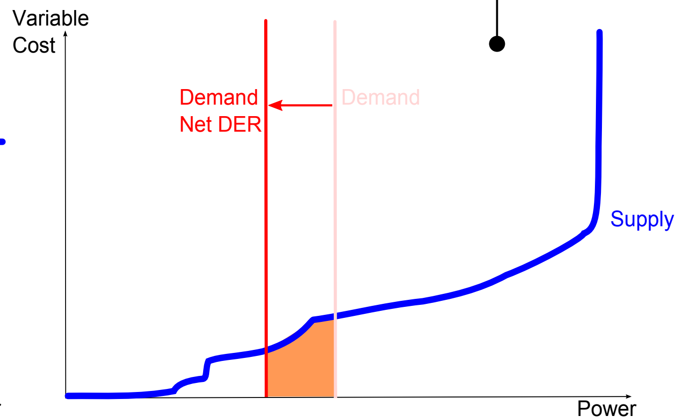
Production cost model: *static generation mix*



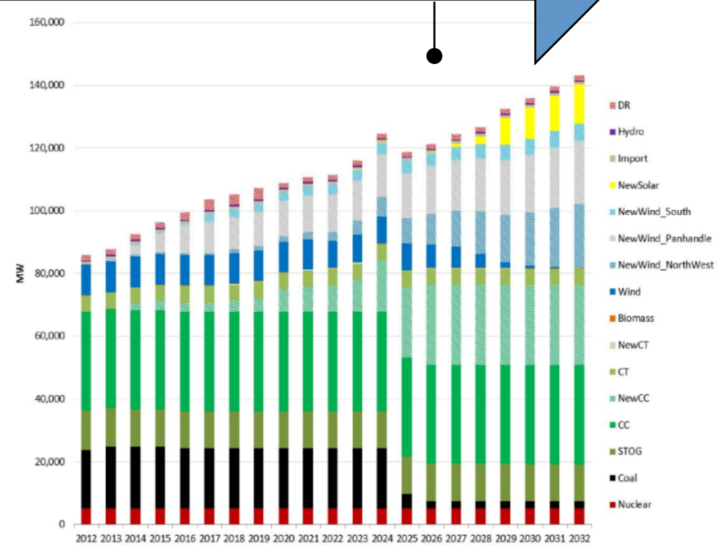




Mix of units on the margin, e.g. off-peak CCGT, on-peak CT



Simple merit-order dispatch



Production cost model: *dynamic generation mix*

Step #2b: Can all DER generation be used or is there a need for some curtailment?

- When the system is constrained, DER may need to be curtailed rather than displacing generation
  - Curtailed DER does not reduce variable costs
- Curtailment mostly occurs with low load and high shares of DER generation, and is magnified by:
  - Congestion: transmission and distribution constraints
  - Inflexibility in conventional generation: high startup and shut-down costs, long start times or minimum run times, high minimum generation levels for reliability or environmental reasons (e.g. minimum river flows for hydro)
- Only some of the previous methods can endogenously estimate curtailment needs

Step #3: What are the variable costs of marginal units?

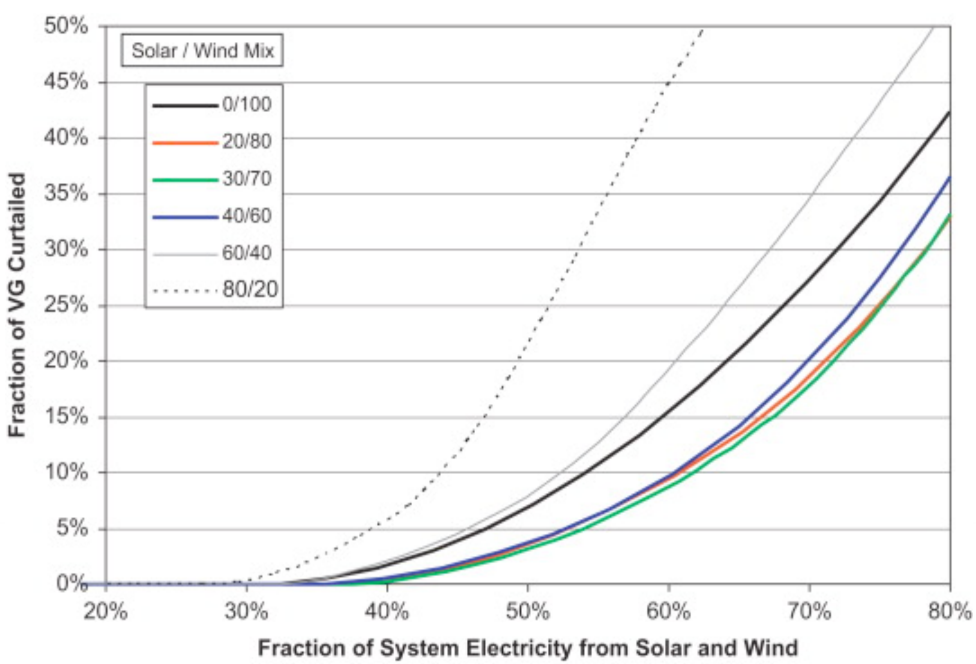
- Variable O&M costs are relatively small: can use data from EIA or others
- Fuel costs are large source of uncertainty and variation in estimates of energy value
- Estimates of energy value need to project variable costs over life of DER
- NYMEX futures and EIA AEO are common sources of fuel price forecasts

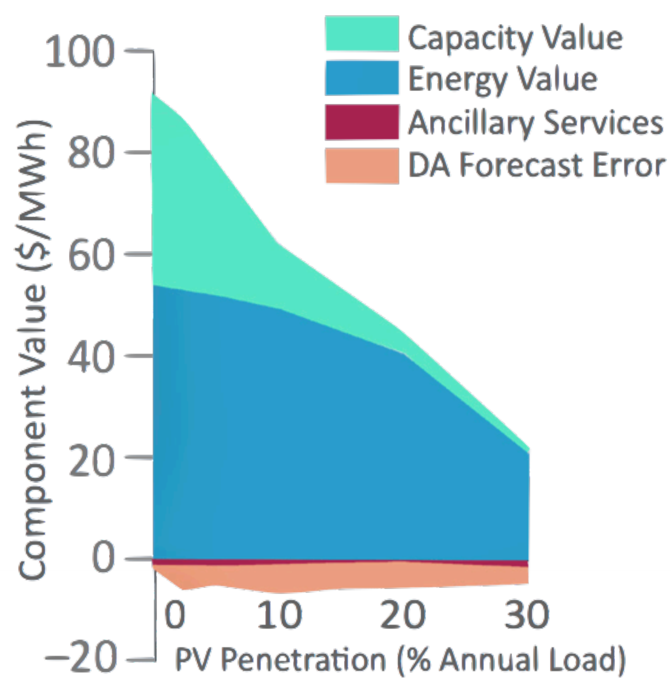
Fundamental Issue #1: DER output profiles

- Not a lot of experience and data for certain types of DERs
  - Solar and wind are among the most straight-forward
  - DR, electric vehicles, storage, CHP all more complicated
- Different assumptions for dispatch/availability can be both justifiable and lead to quite different results
  - e.g. different energy value if you assume storage will be dispatched to reduce customer peak demand charge vs. to minimize system costs
- Dispatch of DER can depend on penetration of other DER
  - e.g. storage dispatch to minimize system costs will be different with low PV vs. with high PV
- Only some of the methods for identifying marginal units can account for different / complicated DER profiles
  - Particularly important for net energy consuming technologies (e.g. storage, electric vehicles), and for DERs that can be dispatched

Fundamental Issue #2: Change in marginal units (& curtailment) with time, DER penetration, or footprint of analysis

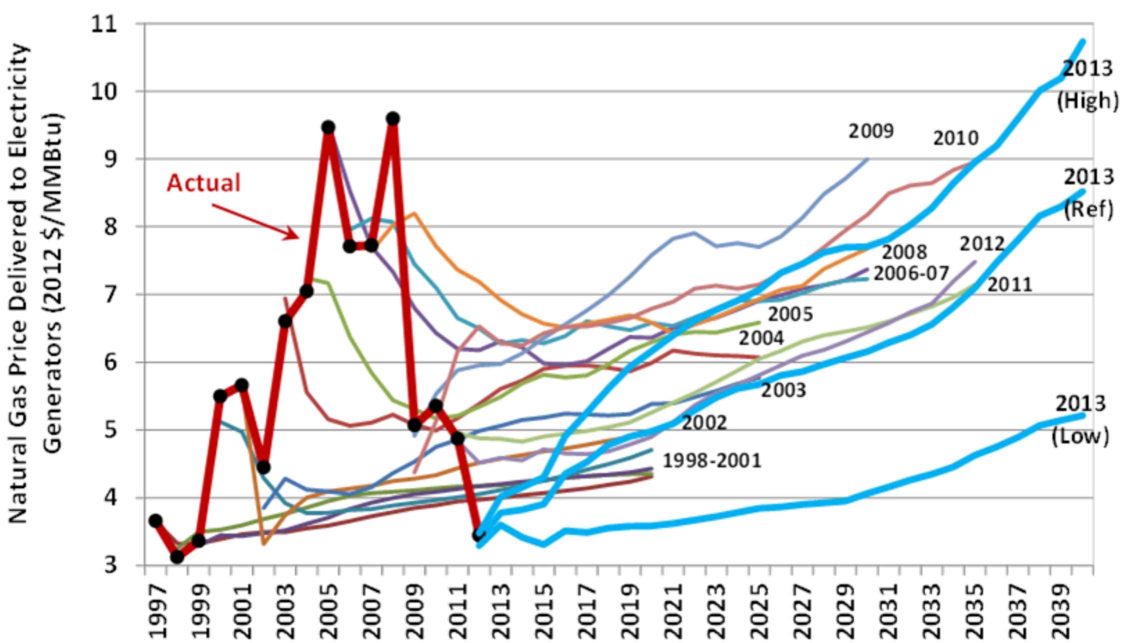
- Which units are on the margin depends on time, DER penetration, and interactions with neighboring regions; also affects curtailment
- Only some methods for estimating which units are displaced endogenously account for these changes, otherwise adjustments need to be made 'manually'
- Changes in marginal unit and curtailment with DER penetration can be important factors at high penetration, but have often been ignored in studies thus far





Fundamental Issue #3: Fuel cost projections and uncertainty

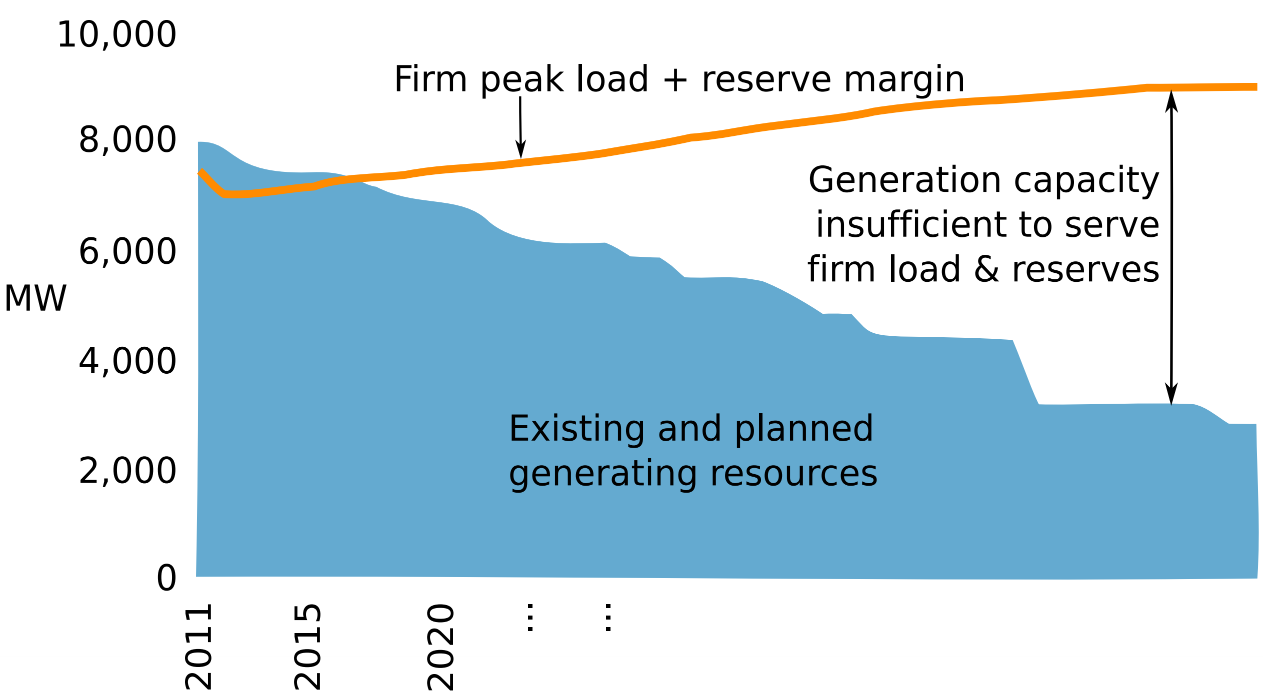
- Future fuel costs are uncertain – how is this addressed?
- Fuel costs vary by location and season – will these differences be the same in the future or do they reflect temporary constraints?
- Lack of fuel costs for some DERs implies overall exposure to fuel price volatility will be decreased (risk “hedge” value)
  - Is this a social benefit? Or does it only inure to the participant? How can it be calculated?



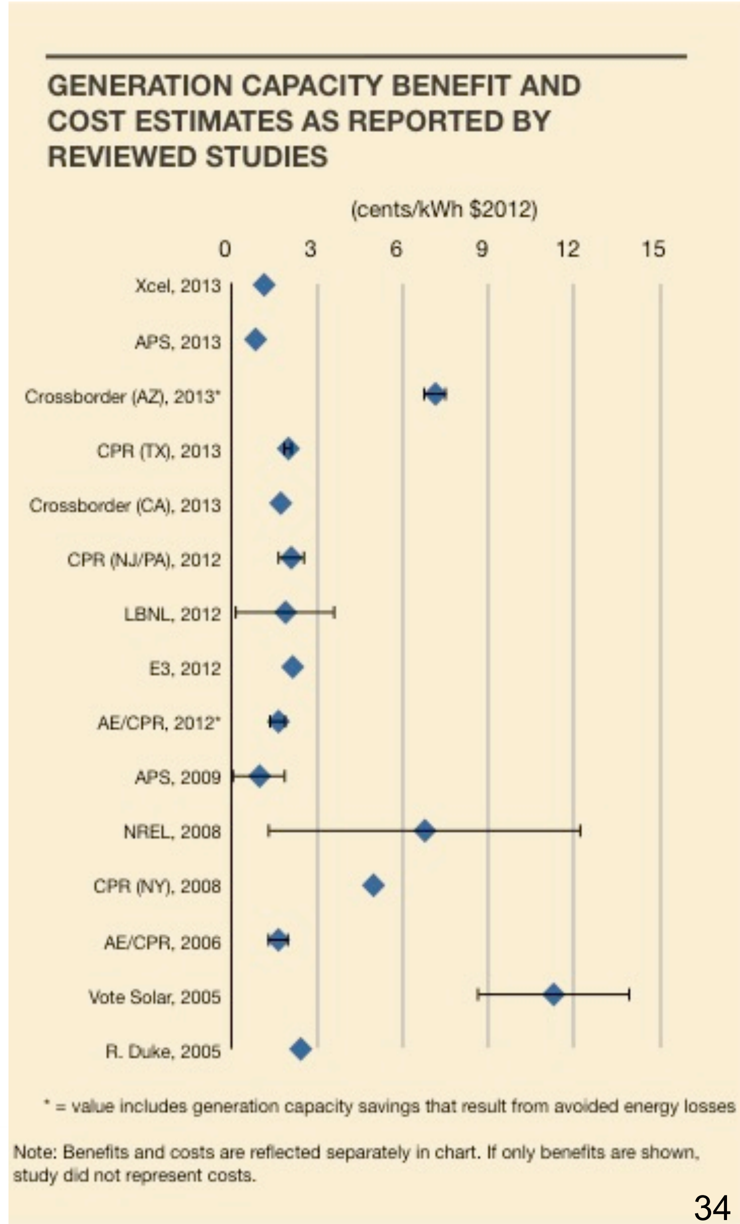
Methods to calculate capacity value

Two main questions / steps:

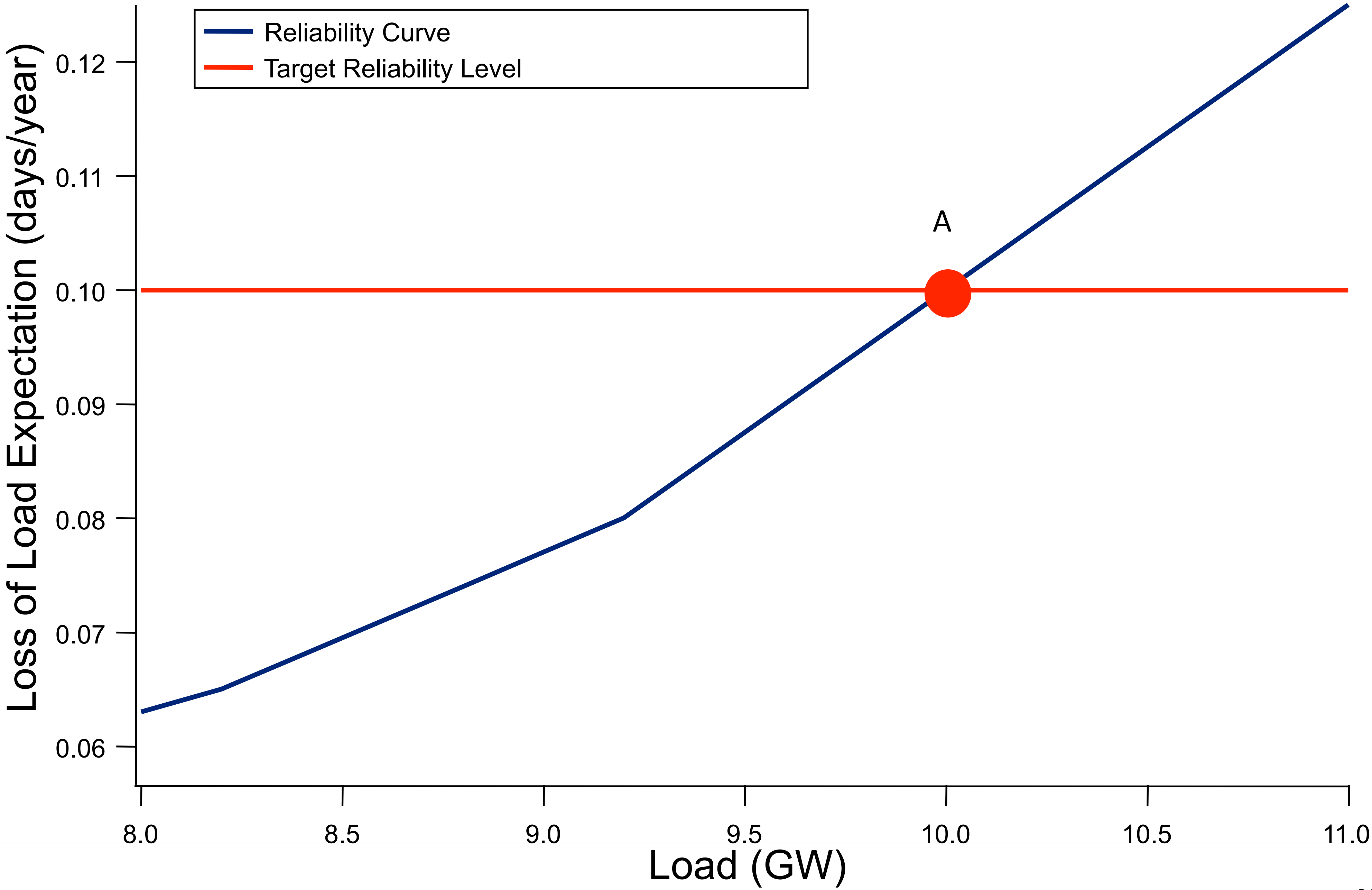
1. How much does DER contribute toward adequacy (i.e. what is the *capacity credit* of DER)?
2. How do you translate that contribution to a monetary value (i.e. what is the capacity value)?



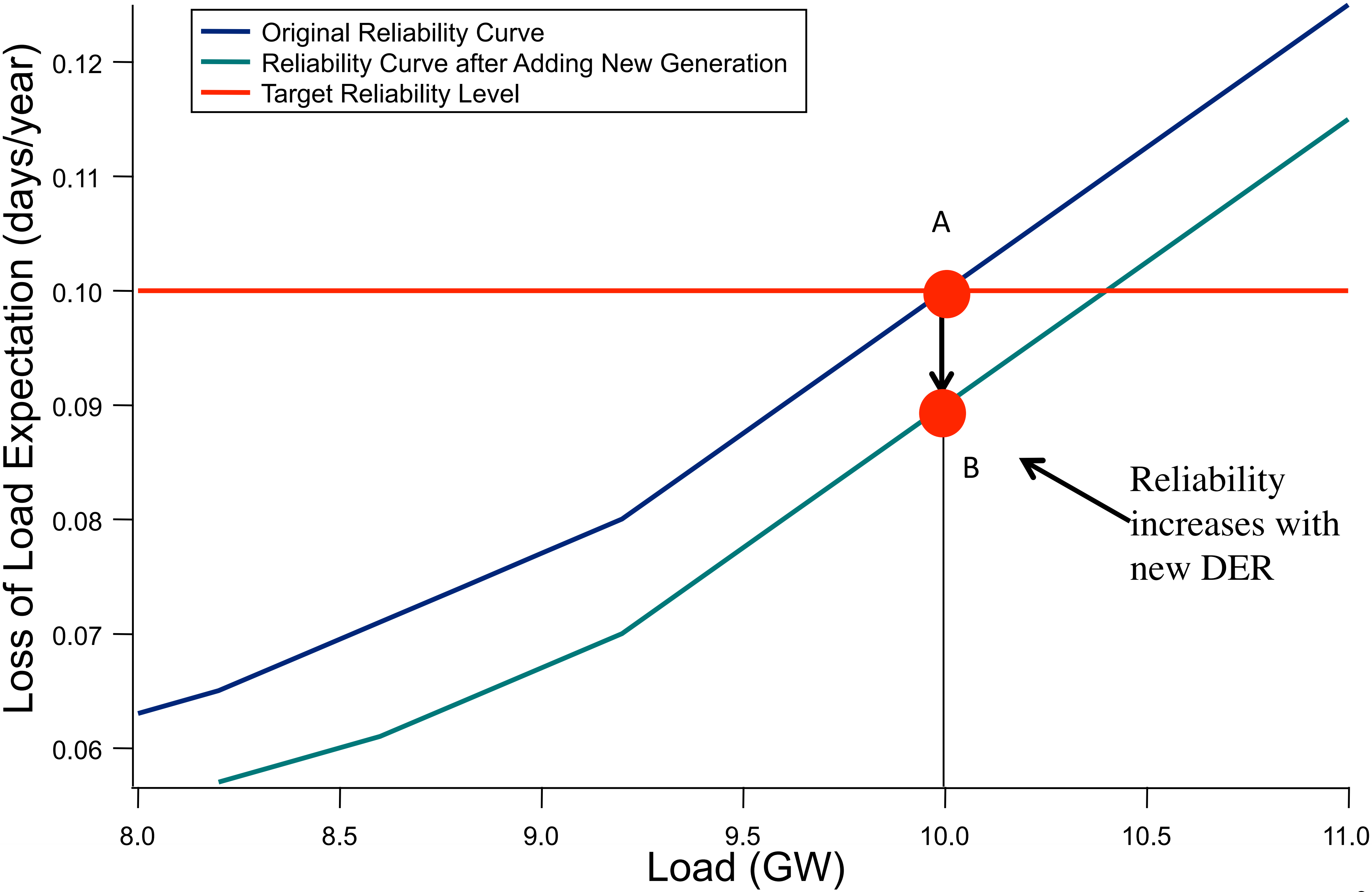
Capacity Value of DPV from RMI Study:



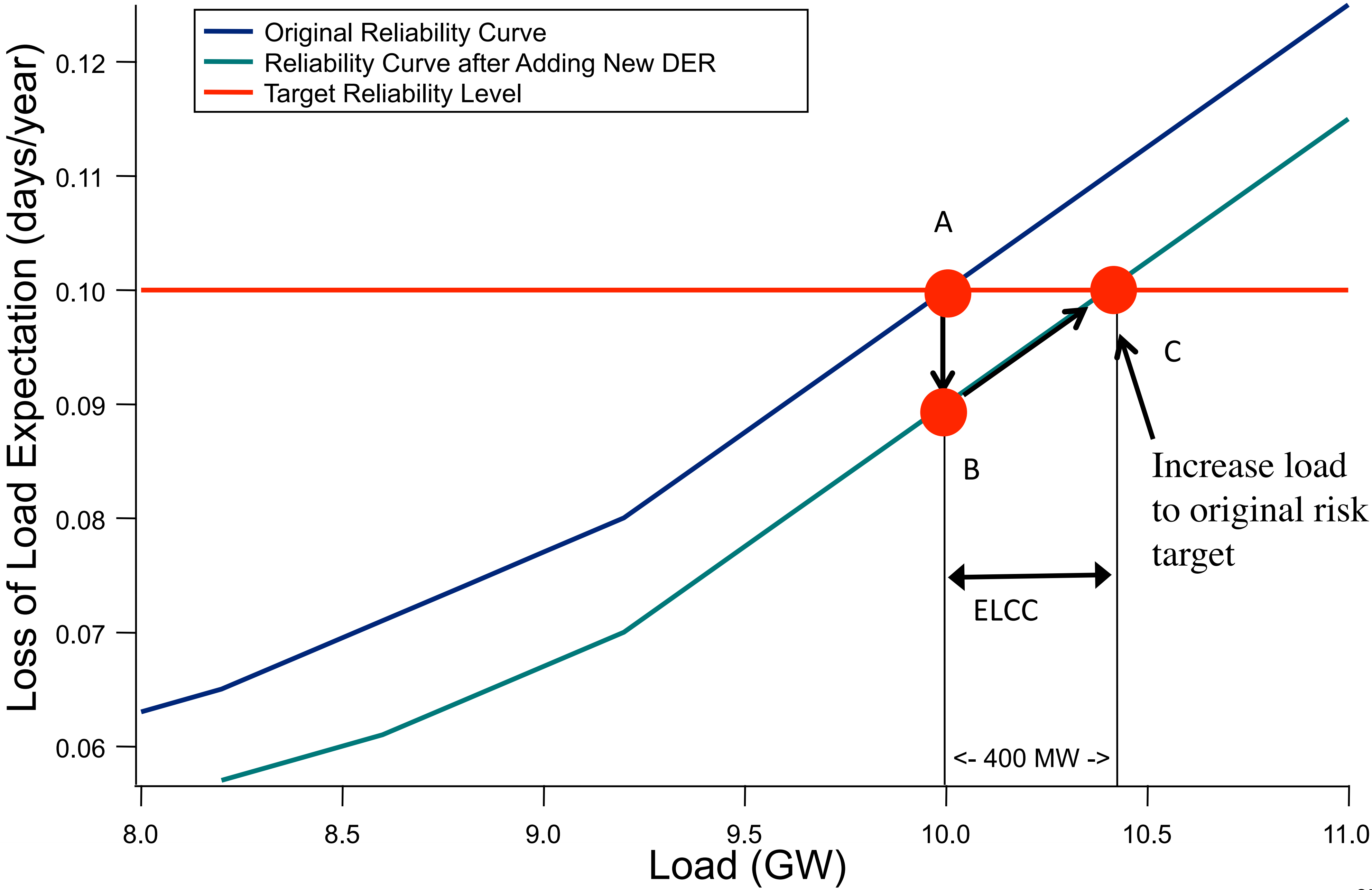
Reliability assessment: How reliable is the system for different levels of peak load?



Addition of DER lowers risk (LOLE) and increases reliability



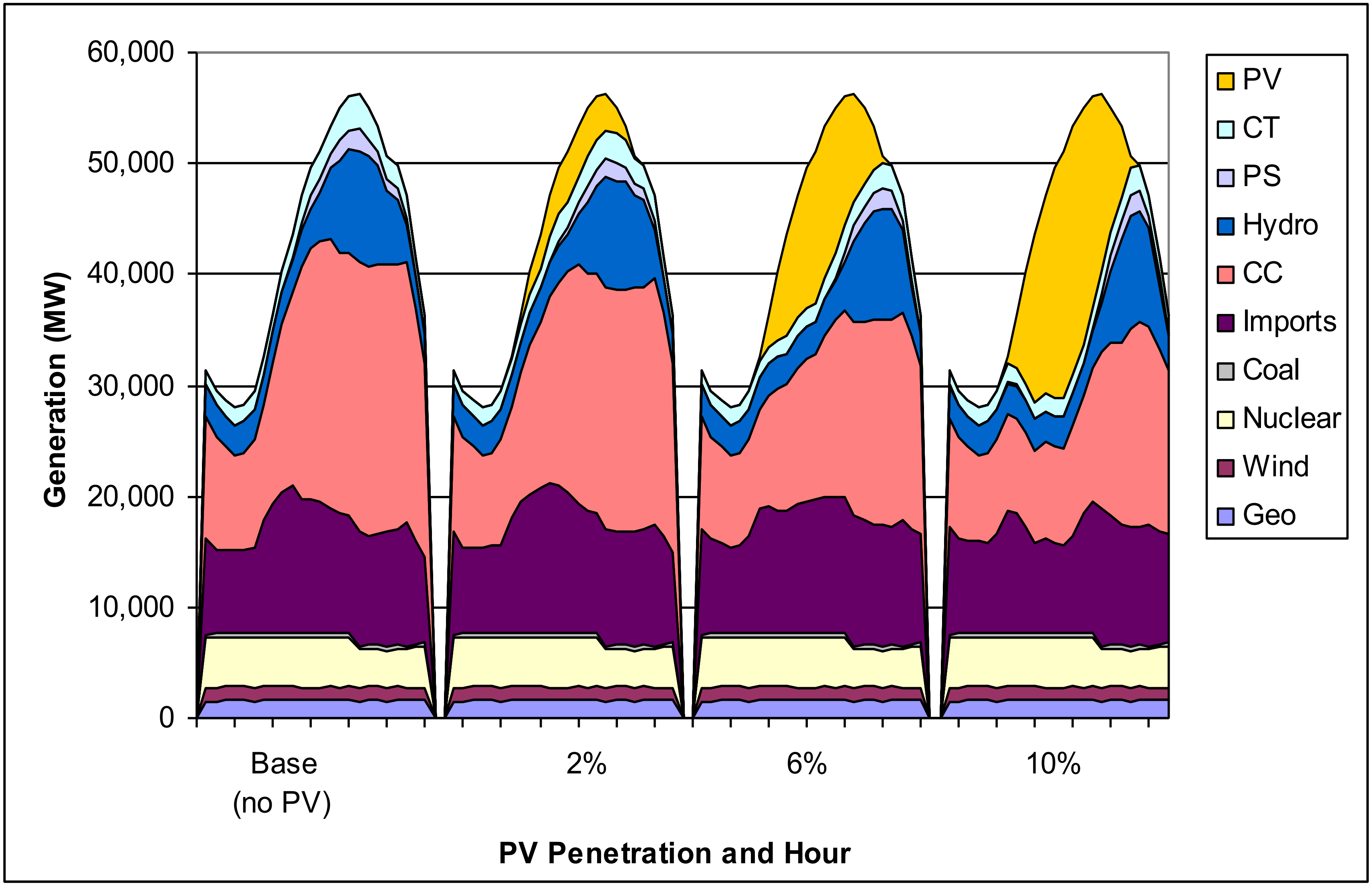
Effective Load Carrying Capability (ELCC): Increase in load to return to target level of reliability with DER



Reliability (ELCC) based approach

- How does ELCC work? Holds the system at constant annual risk level with/without the generator of interest (wind, solar, etc.)
- Utilizes reliability/production simulation model
  - Hourly loads
  - Generator characteristics
  - DER generation pattern (hourly for >= 1 year) time-synchronized with load
  - Calculates hourly LOLP (loss of load probability)
- The hourly LOLP calculation finds high-risk hours: risk can be caused by
  - Peak loads
  - Unit unavailability (planned maintenance)
  - Interchange and hydro schedules/availability
- Most hours/days have LOLP=0 so are discarded: only high-risk/peak hours remain in the calculation of ELCC
- Conventional units ELCC is function of FOR (forced outage rate)

Potential interactions between DERs



Here PV narrows the peak, which could ease the ability of demand response, hydro, storage, etc. to provide capacity. But it also shifts the timing of the peak into the early evening.

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Download all of the original presentations from the U.S. DOE workshop on valuing DER:

http://energy.gov/oe/downloads/estimating-benefits-and-costs-distributed-energy-technologies-workshop-agenda-and

CASE: UM 1719
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 106

Exhibits in Support
Of Opening Testimony

December 14, 2015

Northwest Power and Conservation Council

March 6, 2012

MEMORANDUM

TO: Power Committee

FROM: John Fazio, Senior Power System Analyst

SUBJECT: Wind Load Carrying Capability

As the amount of installed wind grows in the Northwest, it becomes more important to properly characterize its energy and capacity contributions to the power supply. Annual reports, such as BPA's White Book and PNUCC's Northwest Regional Forecast, provide a tally of regional resources and demand. The resulting balance between resources and load is often used as a rough guide to indicate whether the region has ample supply or not. Currently, BPA uses average annual wind generation for the energy component and zero for its capacity component. PNUCC simply aggregates utility provided energy and capacity values for wind resources. The Adequacy Forum has agreed to assume average wind generation for energy and 5% for the sustained-period capacity value (6 hours per day over 3 consecutive days).

None of the above mentioned assumptions regarding the energy and capacity values for wind are desirable. Simply aggregating utility provided data doesn't ensure that proper (or similar) methods are being used. Using average generation for wind's energy contribution is overstating its load carrying capability because of the lack of system flexibility and storage. With infinite storage, average generation would be the correct value to use. With no storage or flexibility, a "worst wind year" approach would likely be better. The real answer is likely somewhere between the results of these two approaches.

The effective load carrying capability (ELCC) of any resource is defined as the amount of annual load (shaped) that it can serve without degrading adequacy. It is commonly expressed in units of percent, namely the amount of load divided by the amount of resource needed to serve that load. A preliminary assessment of ELCC for NW wind shows that for the current amount of installed wind, its ELCC is in the range of 22 to 24 percent. Average wind generation is about 30 to 32 percent. Results also indicate that ELCC will decrease as more wind is added (and more system flexibility is used up). Adding more storage or diversity in wind generation will increase ELCC.

More work is required to develop methods to assess the hourly ELCC for wind.

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The Effective Load Carrying Capability for PNW Wind

Power Committee Meeting
March 6, 2012
Portland, Oregon

Northwest Power and Conservation Council

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Outline

- Reporting capability of wind resources
- Problems with current methods
- Alternatives
- Why ELCC is a better option
- Methodology
- Preliminary results

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Reporting Wind Resources

- BPA's White Book and PNUCC's NRF are tallies of regional resources and demand
- Both energy and capacity contributions for each resource are reported
- Both reports used as a quick assessment for need, thus important to get wind right
- Question: How should we report wind resources?

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Reporting Wind Resources

- NRF – uses utility provided values
- BPA – uses expected average values for energy and 5% for capacity

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Problems with Current Methods

- NRF
  - Not sure how each utility calculates energy and capacity components for wind
  - Likely use different methods
- BPA
  - Because of limited storage, using average generation overstates energy contribution
  - 5% capacity value is based on anecdotal evidence

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Alternatives for Energy Reporting

- BPA investigating a "critical wind year" approach (similar to hydro reporting)
- Can use a monthly percentile value (e.g. lowest 20% value for each month)
- Percentile method yields an annual value that is extremely unlikely and understates contribution
- Other methods examining wind data only

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Alternatives for Capacity Reporting

- Investigate how wind generates during peak load hours and develop a measure
- Use zero %, implying that wind will not be used for capacity expansion plans
- Other methods examining wind data only

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ELCC is a Better Option

- "Effective load carrying capability" is defined as the amount of incremental (shaped) load a resource can serve without degrading adequacy.
- It is usually expressed as a percentage of a resource's nameplate capacity.

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Why ELCC is Better

- ELCC generally accepted as best approach
- ELCC is assessed by performing a system analysis
- ELCC is a function of the system the resource is added to
- It yields a better indication of how much resource is needed to maintain adequacy

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Estimating Annual ELCC

- In a system with infinite storage,
  ELCC = Average wind generation (~30%)
- With no storage,
  ELCC = Worst year wind generation (?%)
- PNW power system has limited storage,
  Worst year < ELCC < Average

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Methodology to Assess Annual ELCC

- Begin with a system with no wind
- Use Monte-Carlo simulation to assess average annual curtailment
- Add an increment of (shaped) load – curtailment will increase
- Add increments of new resource until the average curtailment equals that in the base
- ELCC = load/amount of new resource

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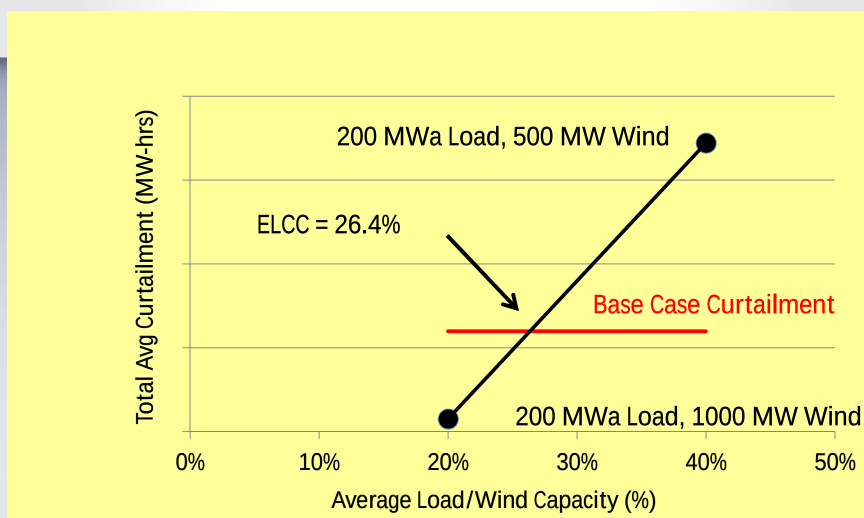
ELCC Results (+200 MWa load)



Preliminary Results

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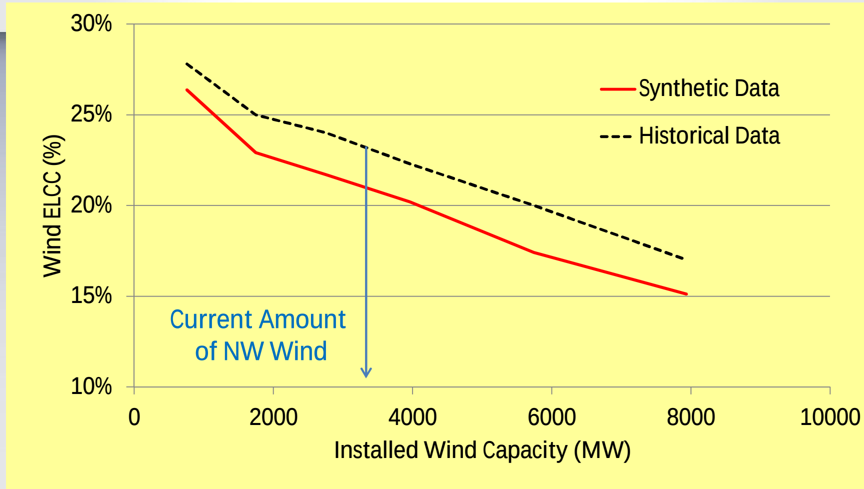
Annual ELCC – Synthetic vs. Historical Data



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Preliminary Results

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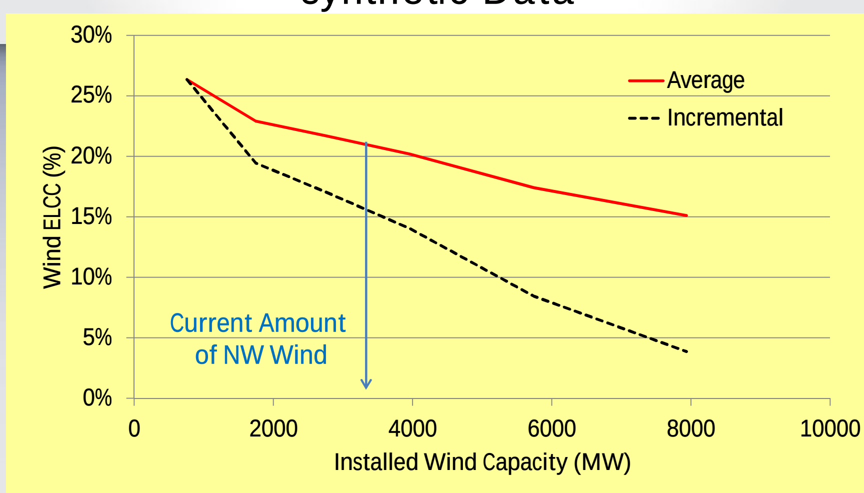
Average and Incremental ELCC Synthetic Data



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Preliminary Results

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Observations

- ELCC declines with increasing amounts of wind because system flexibility is used up
- Eventually wind ELCC will flatten out
- Average annual wind generation is about 30%, yet aggregate ELCC is 22 to 24%
  Thus, can't plan on average wind generation
- Adding storage will increase ELCC
- Adding more diverse wind generation will also increase aggregate ELCC

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Future Work

- ELCC is likely very sensitive to wind data, thus developing more robust data is critical
- This methodology should be appropriate to assess monthly ELCC values
- Assessing hourly (capacity) ELCC values for wind will be more challenging

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CASE: UM 1719
WITNESS: JOHN CRIDER

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 107

Exhibits in Support
Of Opening Testimony

December 14, 2015

Effective Energy and Capacity Contributions of Wind Resources

OPUC Conference Call
August 17, 2015

Northwest Power and Conservation Council

Outline

- Effects of Wind on Hydro Peaking
- Effective Load Carrying Capability
- Associated System Capacity Component
- Additional Topics
  - Wind's Impact to Hydro/Thermal Dispatch
  - Wind's Impact to Oversupply

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Effects of Within-hour Wind Reserves on Hydro Capability

- **INC Reserve** – Generation reserved during peak-load hours that can be turned on, in case wind generates less than expected
- **DEC Reserve** – Generation running during off-peak hours that can be turned off, in case the wind generates more than expected

- Using hydro to carry these reserves decreases its peaking capability – the greater the amount of installed wind, the greater the required reserves

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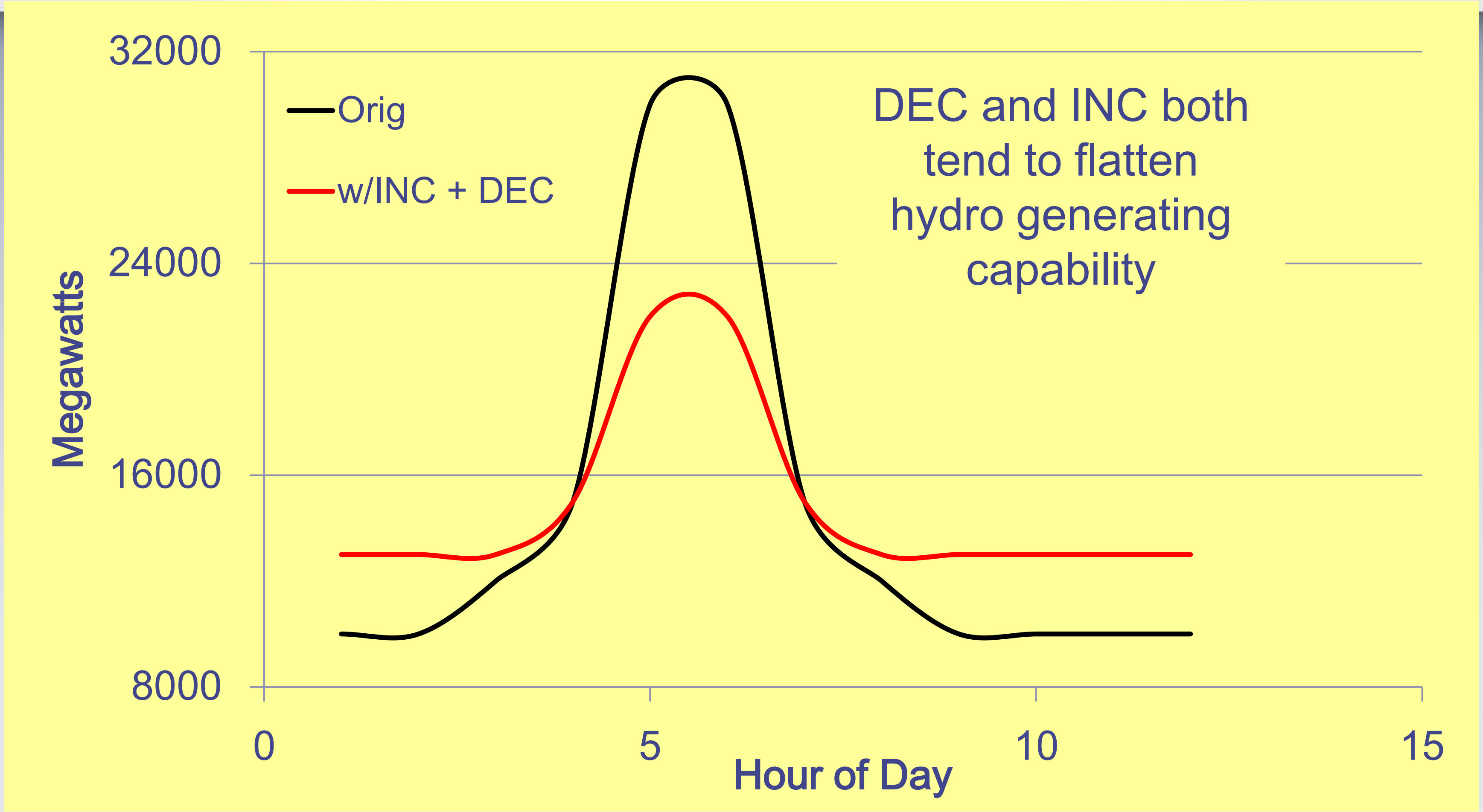
Effects of INC and DEC Reserves on Hydroelectric Capability



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Effective Load Carrying Capability for Wind

- Effective Load Carrying Capability is generally defined as the amount of incremental load a resource can serve without degrading adequacy.
- It is usually expressed as the amount of incremental load divided by nameplate capacity required to maintain adequacy.

- The Council defines ELCC in terms of annual average load and, as such, represents the effective annual average load carrying capability

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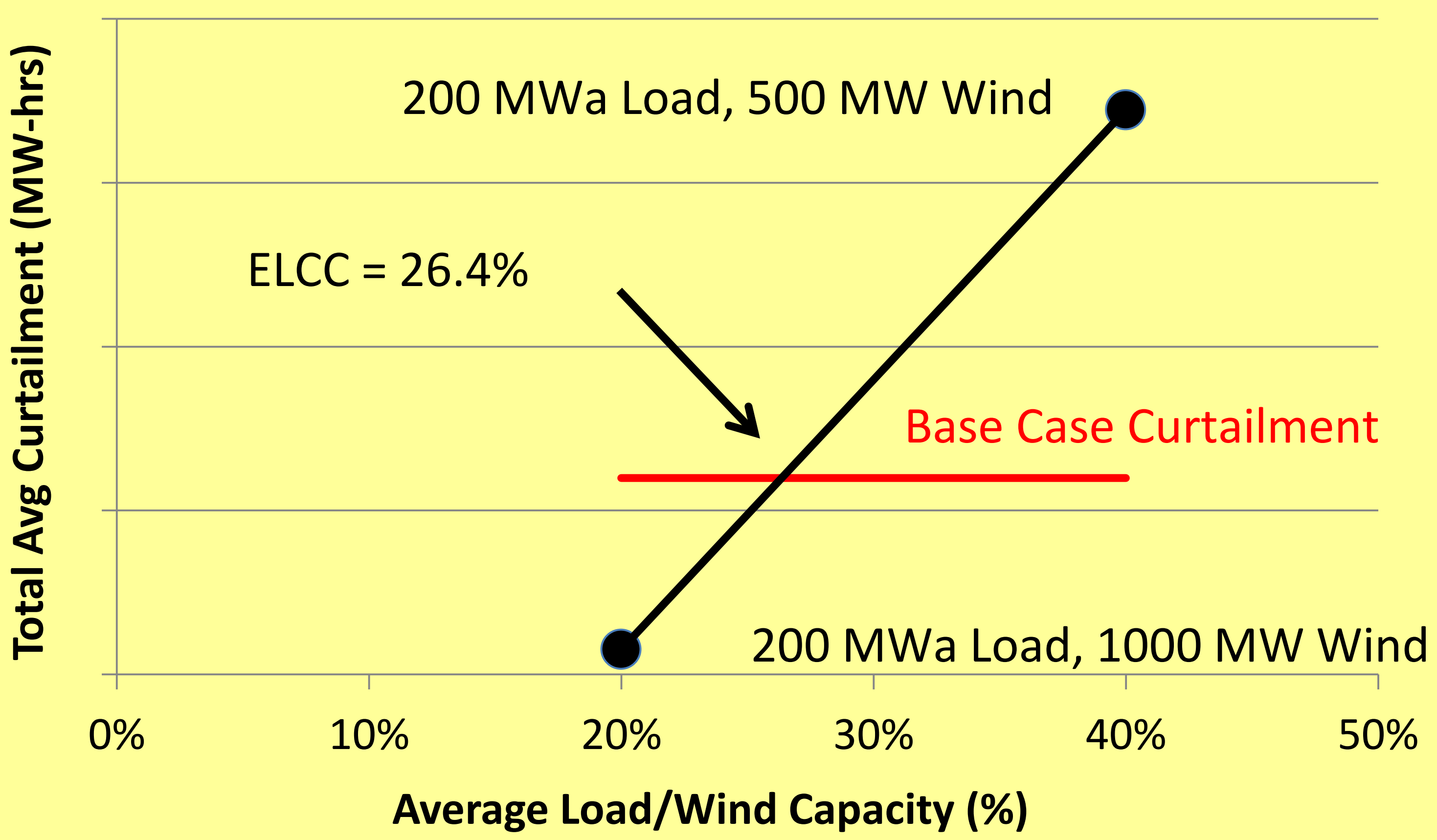
Calculating ELCC

- Begin with a system that is adequate (i.e. LOLP = 5%)
- Assess average annual curtailment
- Add an increment of (shaped) load – curtailment will increase
- Add increments of new resource until the average curtailment equals that in the base
- ELCC = annual load/new resource capacity

ELCC Results for +200 aMW Load

Staff/107
Crider/7



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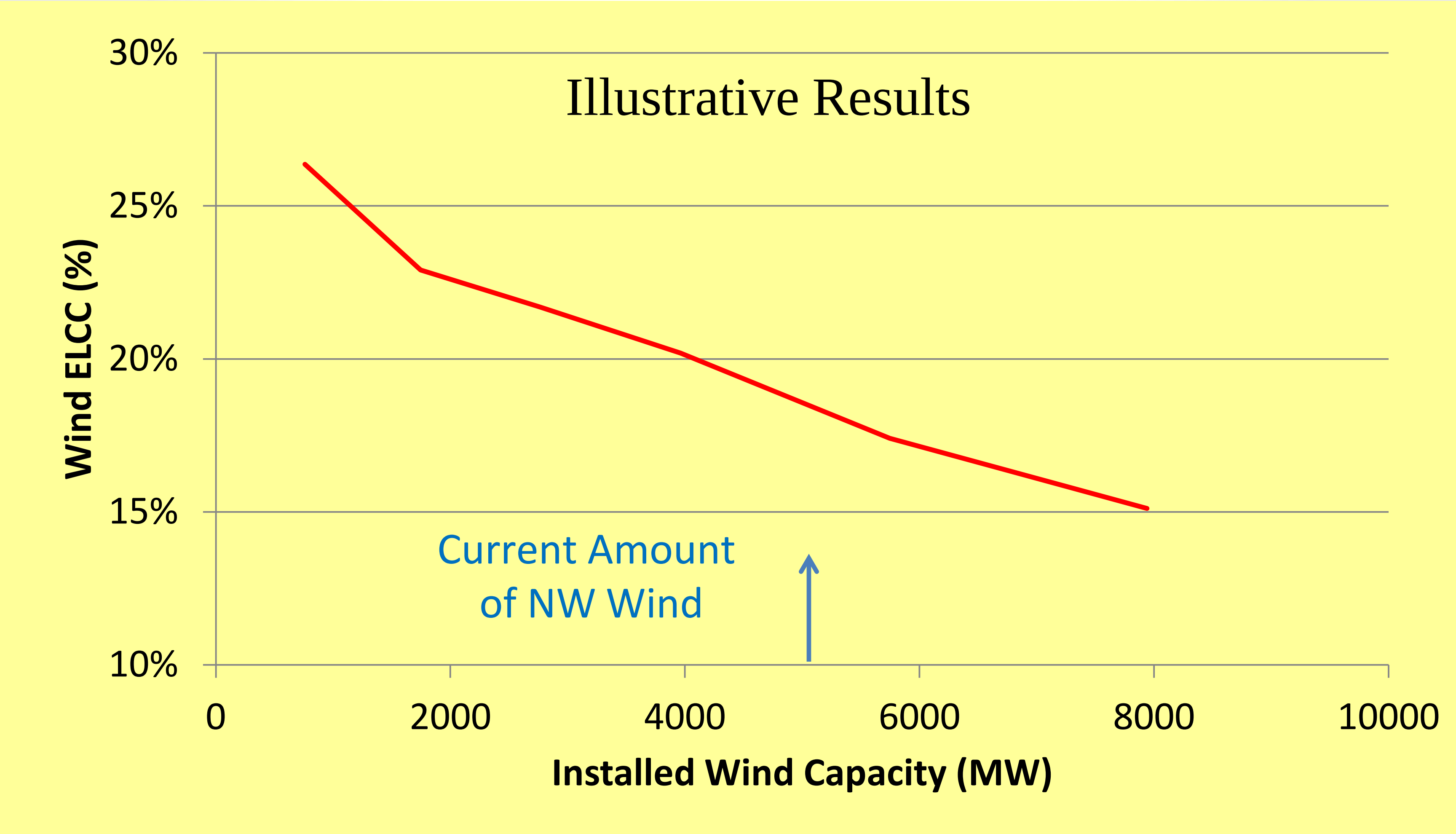
Illustrative Results

ELCC[1] – Using Synthetic Wind Generation



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[1]New within-hour balancing reserves were used for each amount of added wind capacity.

Peaking Capability for Wind

- How much peaking capability can wind provide?
- Does this just mean during the peak hours of the day?
- No, because curtailments don't always occur during the peak hours.

Rough Estimate

- Take all simulated curtailment hours
- Sort by highest curtailment
- What is the average wind generation during the top 10% of the worst curtailments?
- Answer is 5%
- This only provides an initial educated guess for the peaking capability of wind

Associated System Capacity Component

- Associated System Capacity Contribution (ASCC) is the capacity credit for resources that are integrated into an existing power system with storage.☐
- Start with an inadequate case (i.e. LOLP > 5%)
- Using the curtailment record, calculate the amount of capacity-only needed to get to an LOLP of 5%
- Determine how much nameplate capacity is needed to get to an LOLP of 5%

- ASCC = Capacity-only need/Nameplate Capacity

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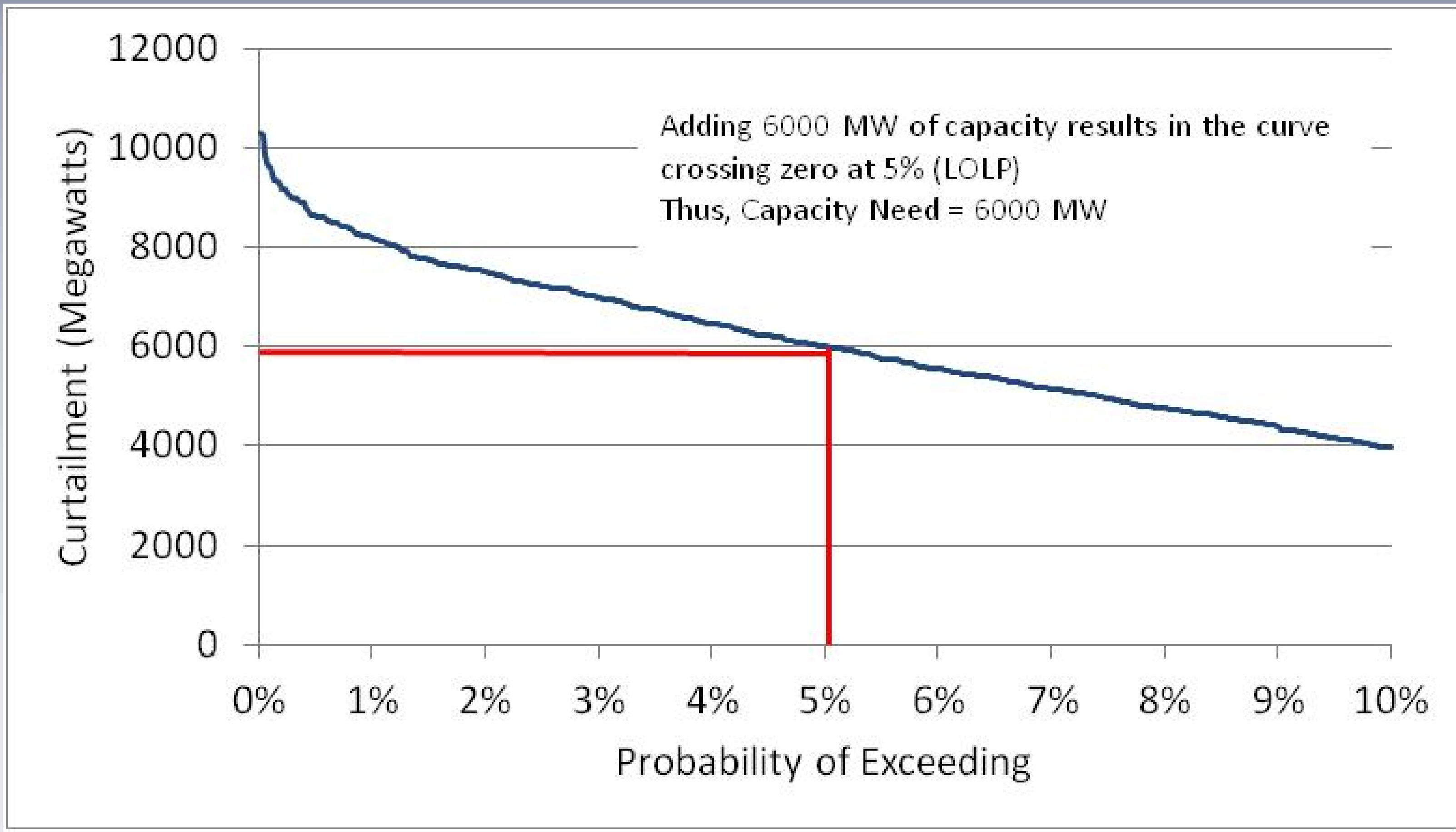
Peak-Hour Curtailment Duration Curve



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Examples of ASCC

- 2026 high load case with existing resources only – LOLP = 50%
- Use curtailment record to assess capacity-only need – 5,850 MW
- How much nameplate CCCT to get 5% LOLP – 4,400 MW
- ASCC (CCCT) = 5,850/4,400 = 1.3

- Same process for Energy Efficiency
- ASCC (EE) = 5,850/4,900 = 1.2

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ASCC for Wind Resources

- Start with an inadequate case (i.e. LOLP > 5%)
- Use curtailment record calculate capacity-only need
- Add sufficient wind nameplate capacity until LOLP = 5%
- ASCC = capacity-only need/nameplate
- Study not yet done – needed to fix anomalous shoulder curtailment problem

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ELCC and ASCC

- ELCC tells us how much incremental average annual load wind can supply without degrading adequacy.

- ASCC tells us how much effective peaking capability wind can provide without degrading adequacy.

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General Observations

- ELCC and ASCC both decline with increasing amounts of wind because system flexibility is used up
- Adding storage should increase both
- Adding more diverse wind generation should also increase both

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Additional Topics

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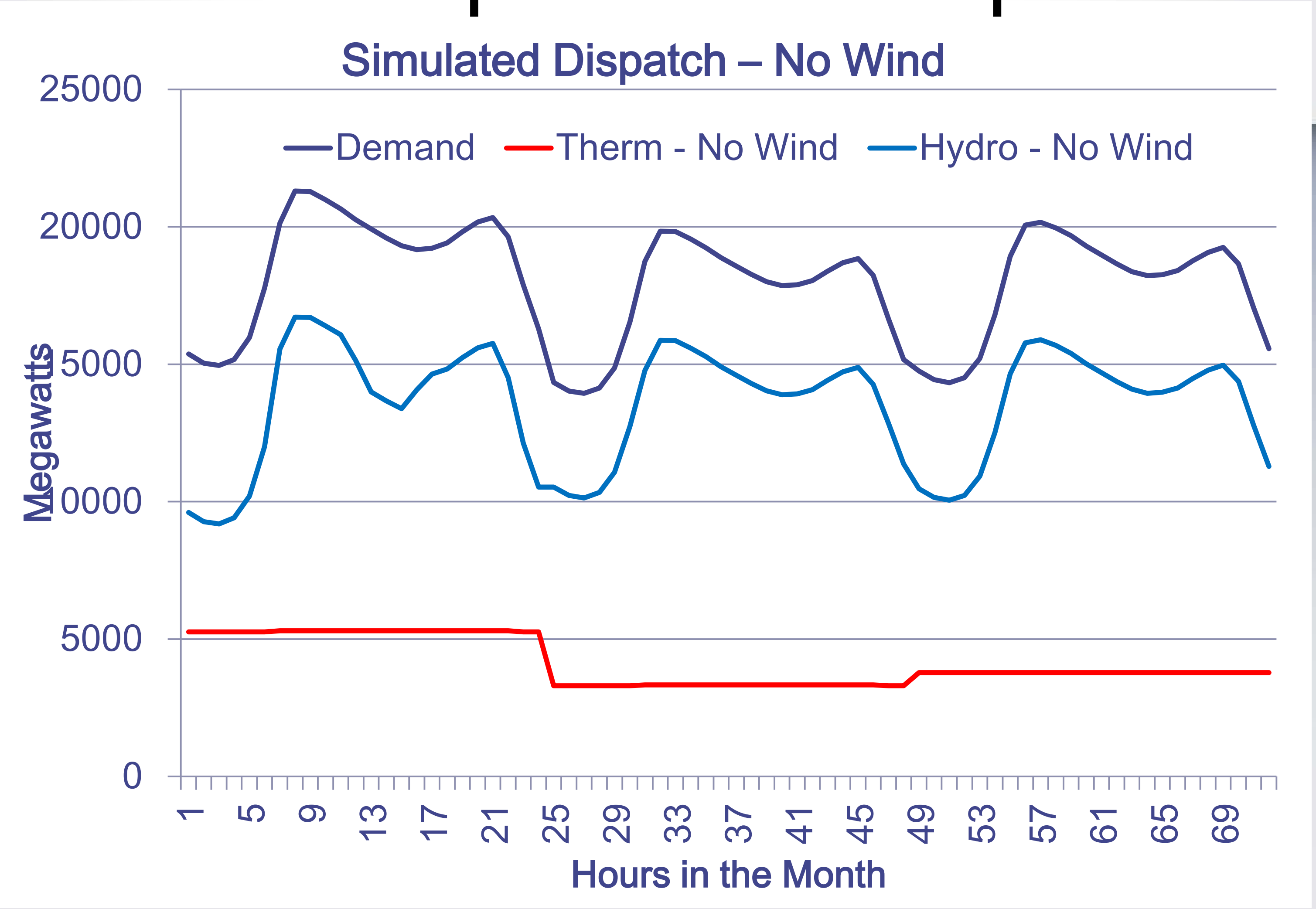
Wind's Impacts to Dispatch



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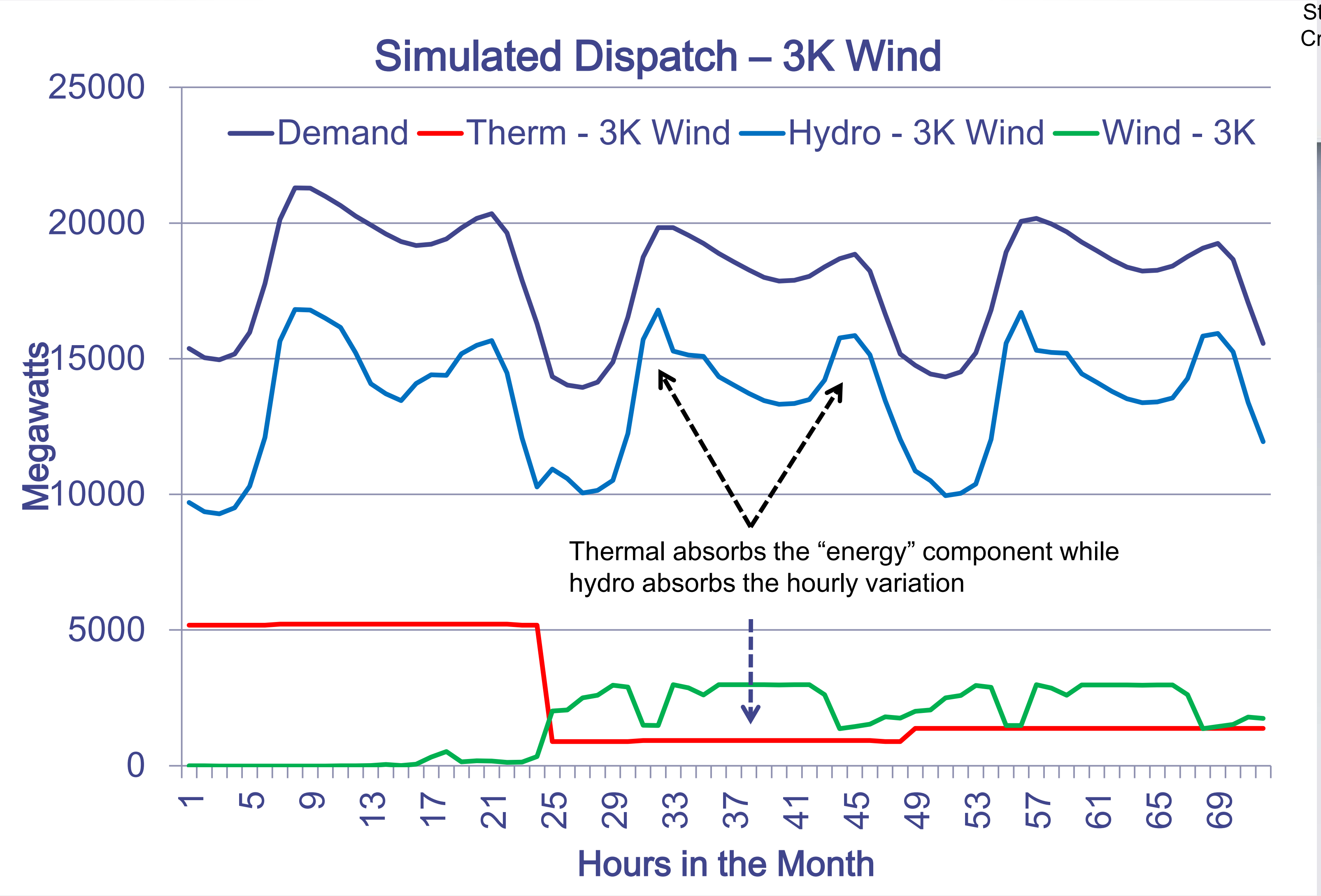

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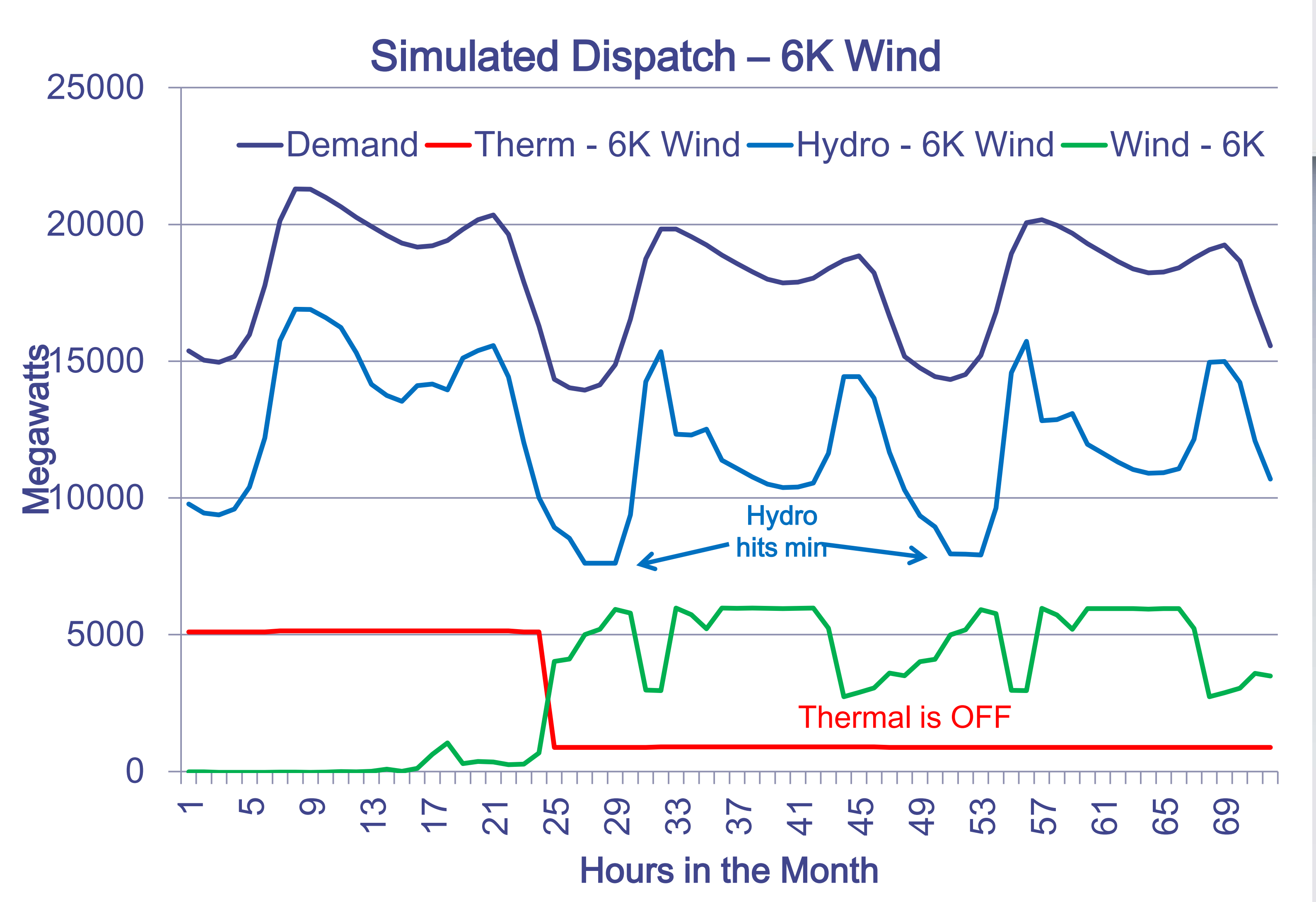

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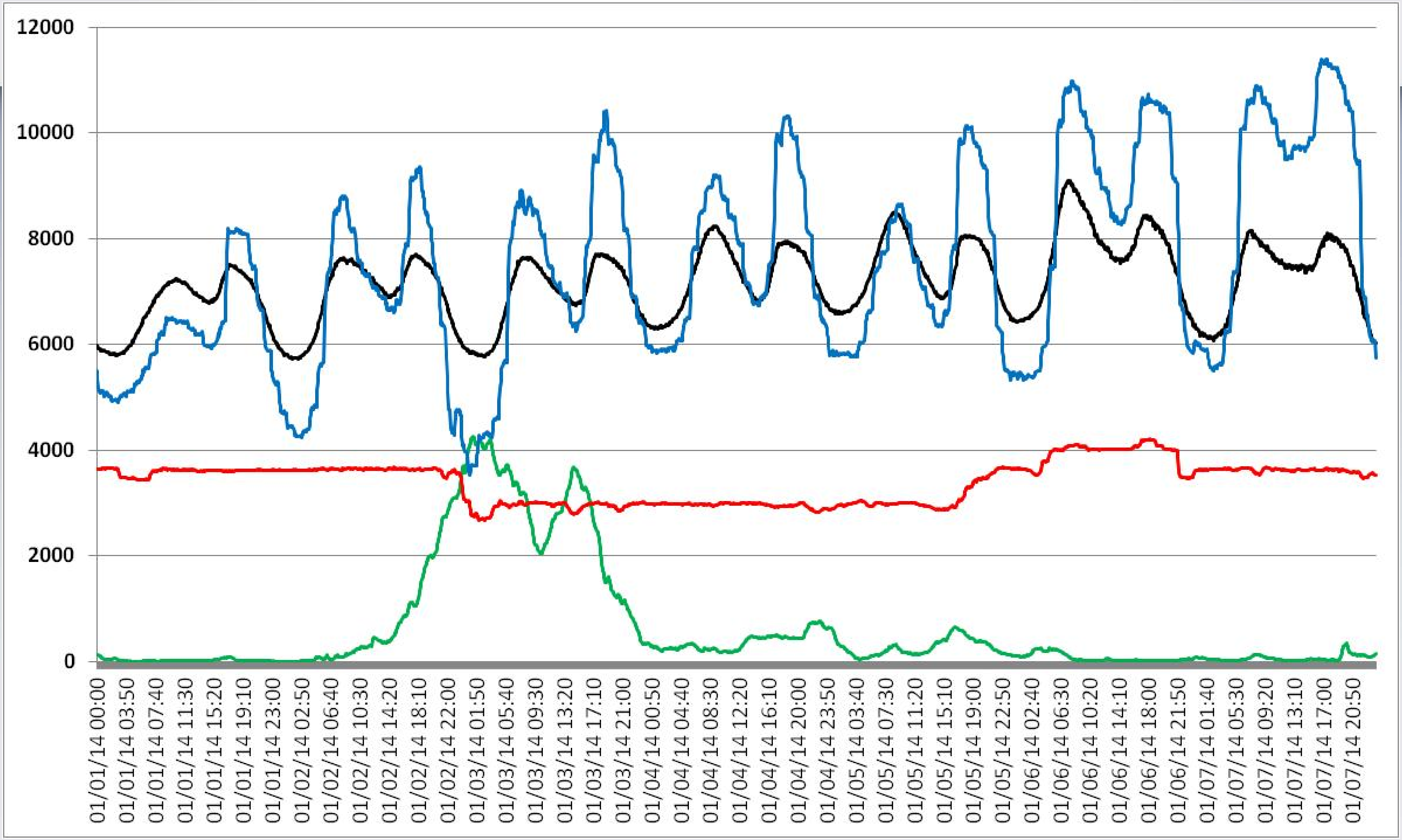
Historical BPA Data Jan 2014



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Oversupply Conditions

Oversupply conditions occur when the minimum system generation exceeds firm load and secondary sales markets.

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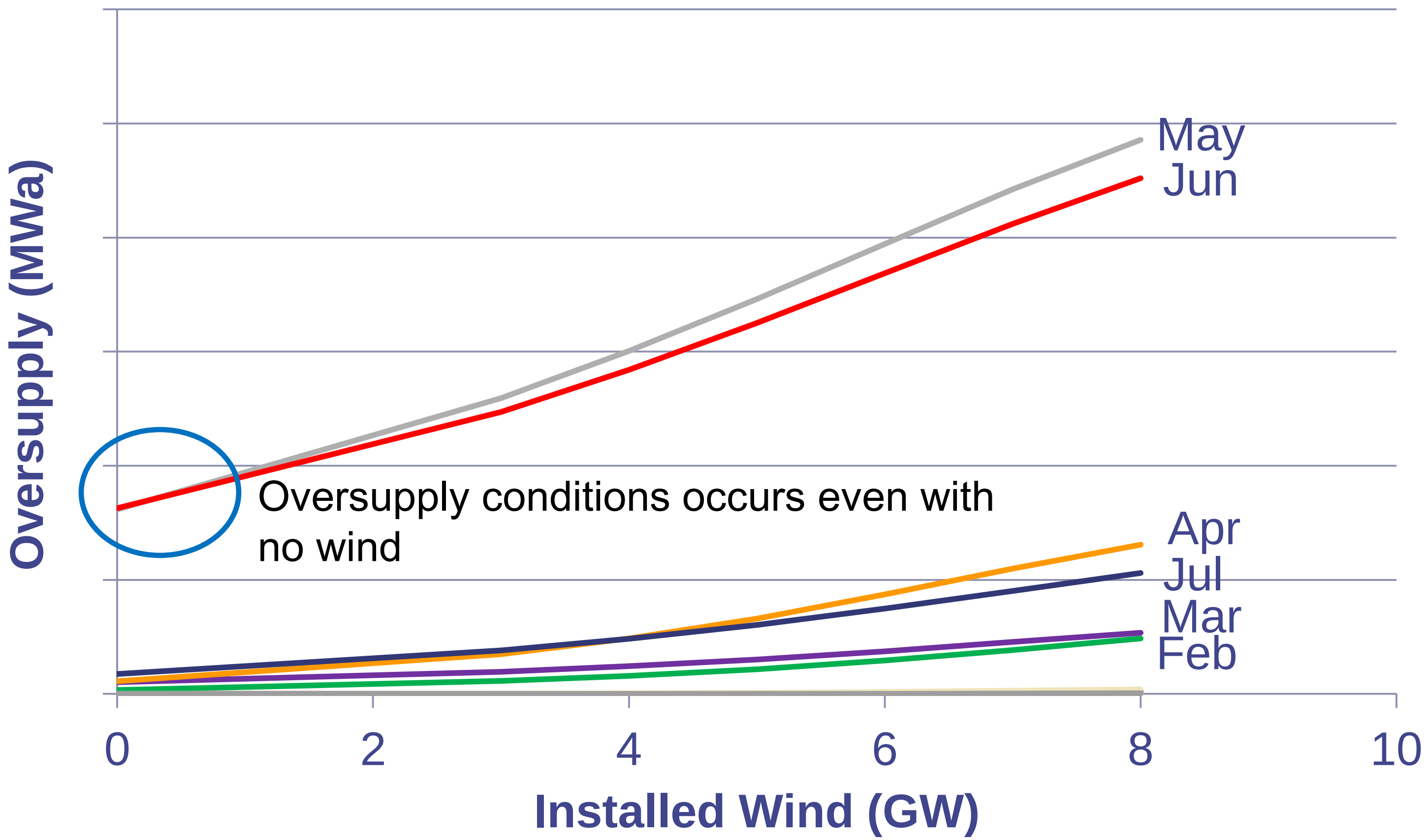
Oversupply in Average Megawatts[1] (averaged over all hours of the month)



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[1]No sales market assumed in this case

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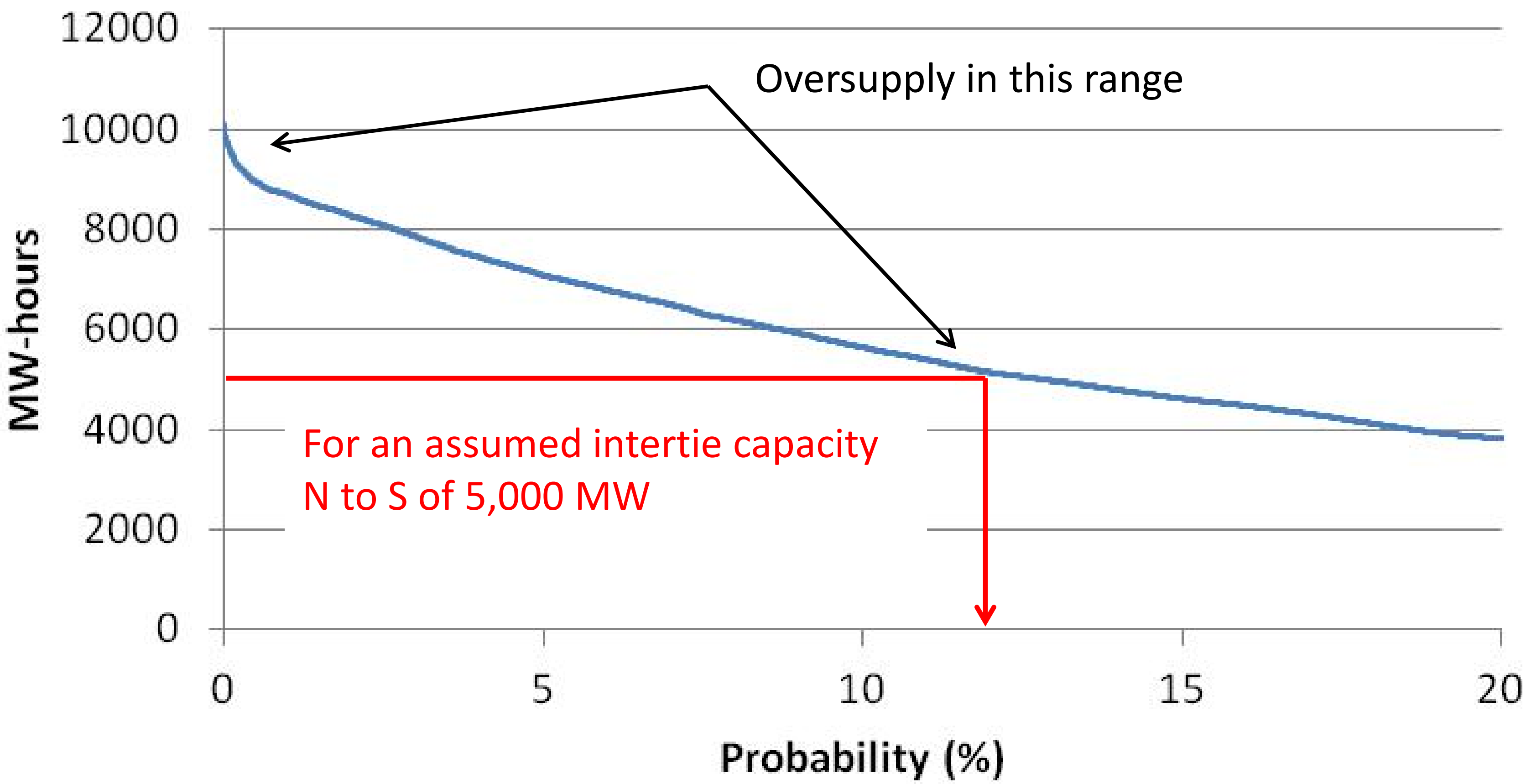
Oversupply Probability Curve



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