Wholesale Electricity Market Design with Increasing Levels of Renewable Generation: Revenue Sufficiency and Long-Term Reliability

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Abstract

This paper discusses challenges that relate to assessing and properly incentivizing the resources necessary to ensure a reliable electricity system with growing penetrations of variable generation (VG). The output of VG (primarily wind and solar generation) varies over time and cannot be predicted precisely. Therefore, the energy from VG is not always guaranteed to be available at times when it is most needed. This means that its contribution towards resource adequacy can be significantly less than the contribution from traditional resources. Variable renewable resources also have near-zero variable costs, and with production-based subsidies they may even have negative offer costs. Because variable costs drive the spot price of energy, this can lead to reduced prices, sales, and therefore revenue for all resources within the energy market. The characteristics of VG can also result in increased price volatility as well as the need for more flexibility in the resource fleet in order to maintain system reliability. We explore both traditional and evolving electricity market designs in the United States that aim to ensure resource adequacy and sufficient revenues to recover costs when those resources are needed for long-term reliability. We also investigate how reliability needs may be evolving and discuss how VG may affect future electricity market designs.

Keywords: Resource adequacy, missing money problem, variable generation, VG

1 Introduction

Variable generation (VG) such as wind and photovoltaic solar power has increased substantially in recent years. In previous power system studies on VG, at least four unique characteristics have been identified for these resources. First, VG increases the variability of net load (load minus VG) because its available power changes through time based on changing weather patterns (i.e., wind speed or solar irradiance). Second, VG increases the uncertainty of the net load (i.e, increases net load forecast error) because the available power cannot be perfectly predicted at all time horizons. Third, although it has significant fixed capital costs, VG has near-zero or zero variable production costs because of the free source of energy. When production-based subsidies exist, this variable cost can be negative. Finally, VG has unique diurnal and seasonal patterns that reduce its capacity value relative to most conventional resources. This is because periods of

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high-energy output may not correspond to times of high demand (or risk of insufficient generation) when considering the power system's resource adequacy requirements.

These characteristics create unique challenges for planning and operating the power system, and they can also influence the performance and outcomes of electricity markets. At the same time, electricity market design must be robust enough to allow the market/system operator to make the most efficient use of the system, given the many constraints; thus, the market characteristics must be reflective of the physical nature of the power system.

This article focuses on specific market design issues that arise from the VG characteristics listed above as related to resource adequacy and revenue sufficiency for long-term reliability. Specifically, we discuss: (1) resource adequacy, including newer methods of determining adequacy metrics, and (2) revenue sufficiency and how existing and evolving market designs may enable resources to retrieve sufficient revenue to ensure long-term resource adequacy. The focus here is on the investment time horizon and the installation of sufficient generation capability. Operational issues, which are closely related, are addressed in a follow-on article (Ela et al. forthcoming).

Resource adequacy processes aim to ensure that sufficient resources are installed and available when needed to reliably meet the load. Resource adequacy requirements vary by region but are generally based on metrics that quantify the long-term reliability of the system. A common approach to quantifying resource adequacy is the planning reserve margin (PRM) (NERC 2011). For example, NERC use a PRM as the primary metric for assessing future resource adequacy in its long-term reliability studies (e.g., NERC 2014). The PRM is usually defined as the percentage by which installed capacity exceeds annual peak demand. In most regions of the United States, the PRM is designed such that involuntary load shedding due to inadequate supply is limited to 1 day every 10 years. As discussed in more detail below, traditional PRM metrics are insufficient for quantifying risk because they do not account for each unit's relative contribution to reliability. Instead, probabilistic methods, such as loss of load expectation (LOLE), are preferred because they are designed to capture times of highest risk and account for the impacts from the capacity value of VG and thermal plant outage rates.

Revenue sufficiency generally refers to the objective of ensuring that resources have sufficient opportunity to recover costs. Regulatory processes have been developed to allow resources sufficient opportunity to recover both their fixed and variable costs, even though short-term conditions and prices may not be sufficient to allow cost recovery. Proper market designs should allow those resources that are needed to ensure long-term reliability to recover their total costs and remain in the market.

In the past, electricity supply in the United States was typically considered a natural monopoly that was provided by vertically integrated utilities under cost of service regulation. However, in the mid-1990s competitive wholesale markets for energy—and in some cases capacity—were adopted in response to excessive PRMs, nuclear resource cost overruns, and legislative deregulation. Currently, more than two-thirds of the electricity consumption in the United States is purchased within restructured independent system operator (ISO)/regional transmission organization (RTO) electricity markets, which are highlighted in Figure 1 for all of North America. The common market design framework reflects a pool-based market in which there

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exists a two-settlement system for day-ahead market (DAM) and balancing/real-time markets (RTM) with co-optimized energy and ancillary services, locational marginal pricing (LMP) for energy, and financial transmission rights (FTR) markets for financial hedging. Ancillary services are used to support power system reliability and perform the necessary services that the energy market cannot provide. FTRs are cleared in forward markets and are instruments that hedge against locational differences in energy prices. Market power mitigation procedures exist to limit strategic gaming and market power. Additionally, capacity markets exist in some regions—e.g., PJM, ISO-New England (ISO-NE), and New York ISO (NYISO)—to ensure that enough capacity is maintained and built to meet future resource adequacy needs.

Each market operator conducts auctions for each of the products discussed so that market participants can buy and sell services. Many of these markets are complex in the way they combine the physics of electric delivery with the principles of economics. Each element of a given electricity market design is linked to a facet of the reliability needs of the system, along with measures that allow for economically efficient operation and competition, while limiting market power. There are some differences in the way that quantities and prices are determined among regions. The rules that govern the operations of these markets are always evolving as new technologies enter the market. Throughout this report, we describe how changes to the existing mechanisms may allow for the integration of VG in an efficient and reliable manner.

Figure 1. ISO/RTO market regions in North America where load is served (image courtesy of ISO/RTO Council)

Some argue that without specific capacity adequacy standards and corresponding capacity remuneration rules, it is likely that resources needed for reliable supply would retire based on short-term market conditions (e.g., Cramton and Stoft 2008, Milligan et al. 2012). These

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challenges are compounded under high penetrations of VG because of the low capacity value of VG and an increased need for system flexibility. This brings a new dimension to the traditional resource adequacy question of whether or not sufficient capacity will be deployed to support reliability and adds the question of whether there is sufficient flexibility within that capacity.

Several alternative approaches are available to solve the problems that we identify in this paper. Rather than recommending any single approach, we present an overview of these alternatives. First, we discuss the issues that make ensuring long-term resource adequacy and revenue sufficiency in electricity markets challenging. Then we discuss the current mechanisms for ensuring resource adequacy and the importance of revenue sufficiency requirements. Next, we discuss how increased VG penetrations can change resource adequacy and revenue sufficiency as well as the optimal means of their provision. We present the historical designs that U.S. wholesale electricity markets have used to address these issues. Finally, we present a review of some of the most recent market design changes that have been implemented to address resource adequacy and revenue sufficiency with a focus on how they are evolving to meet the needs due to increased VG. Although certain market characteristics described in this report may point to advantages of specific market design elements, we avoid making specific recommendations.

2 Challenges to Ensuring Long-Term Reliability

The goal of typical modern electricity systems, whether they are operated by regulated monopolies or centrally administered by an ISO/RTO, is to ensure the reliable delivery of electricity at the lowest cost to consumers. To achieve the system requirements necessary to support the security and reliability of the electric grid, adequate market policies must be crafted that address the financial implications of these requirements. Ideally, these policies will procure adequate generation capacity, provide sufficient opportunity for generators to recover both fixed and variable costs if they contribute to resource adequacy, promote the construction and upkeep of a viable transmission network, and incentivize generators to coordinate scheduling resources to meet the variable and uncertain load while maintaining the reliability of the transmission network. Simultaneously, these policies must avoid incentivizing an overbuilt system or overcompensating inefficient units.

Most retail consumers purchase electricity at administered prices that are most often a characterization of average total cost plus an administered profit rate (e.g., cost-of-service regulation). Most consumers are thus insulated from price swings that are, or would be, a function of the relatively volatile cost and marginal wholesale prices of electricity at the bulk system level. In addition, electrical neighbors who wish to purchase different levels of electric reliability are prevented from doing this and must instead purchase the same amount because there is currently no way to differentiate reliability among customers on the same feeder. These demand-side flaws (Stoft 2002) impact the way that electricity markets are designed and create incentive problems for the demand side of the market, because consumers' willingness to pay for electricity and reliability is not reflected in market clearing prices. Reliability targets in the power system exist, in part, because of the nonresponsive nature of demand. When this fact is combined with the long-term nature of generation and transmission investments, substantial economies of scale, and the fact that much of the infrastructure is underutilized most of the time,

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competitive market challenges arise. Thus, bridging the gap between reliability and electricity markets is challenging.

The market challenges presented above have been subject to long discussions and continuous evolution, driven by the dominant generator types, transmission availability, and load. This has resulted in a variety of economic and reliability metrics to assess resource adequacy. These include a method for choosing and assessing the resource adequacy target; determining whether the resource adequacy target has been, or will be, achieved; determining the contribution of each entity toward meeting the resource adequacy target; utilizing the right time horizon for meeting resource adequacy targets (e.g., one year ahead, three years ahead); and ensuring revenue sufficiency of the resources that are needed to achieve the prescribed levels of reliability. In systems that have significant levels of VG, additional items may need to be addressed, such as the impact of VG on reliability calculations and resource adequacy targets; determining how VG contributes toward the capacity adequacy requirement; and ensuring that the system has adequate flexibility attributes to handle the increased variability and uncertainty characteristics of VG in grid operations.

3 Achieving Long-Term Resource Adequacy and Revenue Sufficiency

Resource adequacy has not historically been subject to true market outcomes. Instead of prices that would ration electricity usage during scarcity periods or pre-set price caps that reflect the value of lost load, a somewhat-arbitrary reliability standard defined by policy was introduced along with administered pricing rules that have the effect of muting most forms of price-response from most consumers. Below, we discuss resource adequacy metrics and revenue sufficiency in more detail.

3.1 Resource Adequacy Metrics

To meet long-term resource adequacy needs, system planners use a variety of metrics to understand how much capacity is required, how each resource on the system can contribute to meeting that requirement, and whether resources have sufficient incentive to remain in the market. Determining whether resource adequacy targets are achieved is inherently a probabilistic problem. Well-known methods exist for both generator-specific and system-wide reliability metrics, which are described in detail in Ela et al. (2014). Generator-specific metrics focus on the forced outage rate (FOR), which is the probability that a generating unit would be in an unplanned outage state. System-wide metrics are summarized in Table 1, though we note that definitions for various reliability metrics can vary in practice and across different applications. A common system-wide reliability target in the United States is an LOLE of 1 day in 10 years, which means that the aggregate system load will be met by the aggregate system generation for nearly all time steps in the reliability assessment (usually hourly). Multiple-year data sets are preferred so that tail events can be captured (Keane et al. 2011). Alternative targets can be adopted if desired, and the choice of the reliability target is largely a question of policy preference. A sampling of U.S. regions using these probabilistic-based methods, as well as the non-probabilistic PRM-based method, are summarized in Table 2.

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Table 1. Resource Adequacy Metrics for System-wide Reliability

Reliability Metric	Description
LOLP[a]	Probability that there will be insufficient generation to meet load at a given point in time
LOLE	LOLP multiplied by a given unit of time. Represents only the number of shortfalls and not the size of the shortfall (e.g., 1 day in 10 years)
LOLH[b]	Form of LOLE, usually expressed in hours per year in which there may be insufficient generation supply
EUE[c]	Captures the energy components of inadequacy but does not count the number of occurrences
ELCC[d]	Measures how much more peak load can be added with the introduction of new capacity for a fixed reliability level

[a] Loss-of-load probability
[b] Loss-of-load hours
[c] Expected unserved energy
[d] Effective load-carrying capability

Table 2. Reliability Metrics Used by Selected Markets in the United States (adapted from Pfeifenberger et al. 2013 and WECC 2014)

	Regions	Metric	Target Value
Probabilistic Method	Southwest Power Pool	LOLH	2.4 hours/year
	ISOs/RTOs: PJM, MISO,[a] NYISO, ISO-NE, ERCOT[b] NERC[c] regions: Midcontinent Area Power Pool, some SERC entities (e.g., Duke Energy Carolinas, Progress Energy Carolinas, Entergy), Florida Reliability Coordinating Council APS[d]	LOLE	1 day/10 years
	BPA[e]	LOLP	5%[i]
PRM Method	CAISO[f]	PRM	15%
	SCE&G[g]	PRM	12%–18%
	PNM[h]	PRM	13%

[a] Midcontinent ISO
[b] Electric Reliability Council of Texas
[c] North American Electric Reliability Corporation
[d] Arizona Public Service (part of the Federal Energy Regulatory Commission (FERC)'s Southwest region)
[e] Bonneville Power Administration (part of FERC's Northwest region)
[f] California ISO
[g] South Carolina Electric and Gas (part of NERC's SERC region)
[h] Public Service Company of New Mexico (part of FERC's Southwest region)
[i] This LOLP of 5% reflects the probability that the region would experience a significant power shortage no more than once in 20 years (NWPP 2008).

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Embedded within each of these reliability metrics is the challenge of determining the optimal quantity of capacity to add to the system. The amount of capacity that any generator can contribute to reliability will be subject to interannual variations of the FOR and/or resource characteristics, although the properties of this variability will differ among technologies. As an example, if a thermal plant with an ELCC of 90% to 95% of its installed capacity experienced a forced outage event during high-LOLE peak periods, it could conceivably not contribute toward meeting load in that year. Similarly, wind, solar, and hydro generation are a function of the weather and thus may vary around a long-term average from one year to another, and may vary by an even greater amount on any given day they might be needed. For example, the current California drought is highlighting the interannual variations in the available hydro resource (Gleick 2015).

Although only explicitly listed for a few utilities in Table 2, the PRM is a common metric used for assessing resource adequacy (NERC 2011). In some sections of the United States (e.g., WECC and SERC), no general resource adequacy requirement is enforced, but instead the individual load-serving entities set their own targets with various approaches, subject to regulatory review (Pfeifenberger et al. 2013). An administratively determined PRM is based only on capacity and by itself cannot recognize the influence of generators' FORs. As a result, the PRM alone is an inadequate reliability metric because it cannot distinguish between two systems that have the same installed capacity and peak loads but different FORs. An illustration of this disconnect is shown by Milligan and Porter (2008) in a parametric study of a system based on CAISO. When increasing the FOR on a subset of the thermal units and simultaneously increasing the number of new 100-MW units to maintain a 1 day/10 years reliability target, they found that the PRM required to maintain reliability increased from approximately 15% to nearly 24%. These findings are shown in Figure 2.

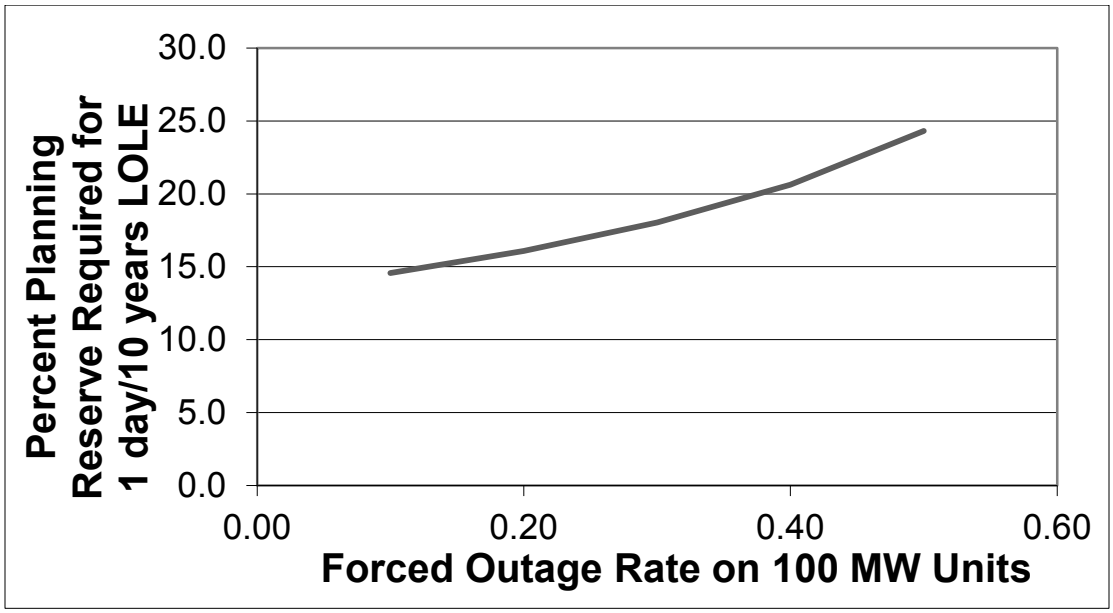

Figure 2. PRM to achieve a 1 day/10 years LOLE is a function of FORs (Milligan and Porter 2008)

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The PRM is an even less precise reliability metric when VG penetration is high. VG availability is largely based on weather patterns rather than forced outage probabilities. Because VG units usually have low capacity values, the PRM of the system changes significantly when the installed capacity (ICAP) is used to calculate the PRM in highly renewable systems. The ICAP is used for calculating the PRM in some cases for some regions[1] (Pfeifenberger et al. 2013). To demonstrate this point, consider the simple system shown in Table 3 that has a peak load of 1,000 MW and 1,150 MW of installed thermal capacity, yielding a PRM of 15%. Now assume that 100 MW of that thermal capacity was replaced with 500 MW of wind with a 20% capacity value such that the system maintained the same LOLE. The new PRM would be 55%, which is deceptively high because it does not account for reliability impacts from the capacity value of wind or the thermal plant outage rates.

Table 3. PRM Does Not Account for Reliability Aspects of Resource Adequacy

	Scenario A	Scenario B
Peak Load	1,000 MW	1,000 MW
Thermal Capacity	1,150 MW	1,050 MW
Wind Capacity	0	500 MW at 20% ELCC
LOLE	1 day/10 years	1 day/10 years
PRM	15%	55%

Thus, system metrics such as LOLE for system needs and ELCC for individual contributions may provide a better estimate for meeting long-term reliability needs, especially if calculated on an hourly rather than daily basis.

A more accurate PRM metric would be based on unforced capacity (UCAP), which is the capacity available after accounting for the expected FOR. For VG, calculating its corresponding contribution to capacity requires sufficient data to be able to evaluate, with confidence, the statistical attributes of VG and identify any statistical relationships with other important parameters, such as load levels (NERC 2011). All regions in the United States use ICAP reserve margins for most reporting purposes, but some of the capacity auctions (PJM and NYISO, as well as MISO's voluntary resource planning auction) are based on UCAP to capture each unit's contribution to system reliability (Pfeifenberger et al. 2013).

3.2 Revenue Sufficiency

The missing-money problem (Stoft 2002) is the concern that even robust energy markets may not provide sufficient revenue for generators to pay for both variable and fixed costs. It predates the current large-scale expansion of VG and is said to be caused, in part, by (1) consumers being shielded from price swings, (2) the existence of price caps, (3) inadequate scarcity pricing, and (4) the inability of different customers to purchase different levels of reliability due to the interconnected nature of the power system. Increased penetrations of VG can exacerbate this missing-money issue by making revenue sufficiency more difficult to achieve, as further discussed throughout Section 4.

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4 Impact of Increased Penetrations of VG on Long-Term Resource Adequacy and Revenue Sufficiency

The introduction of VG can impact resource adequacy and revenue sufficiency in many ways. First, due to their inherent variability, VG resources do not contribute their full rated capacity to system reliability.

Second, VG increases the amount of variability and uncertainty in the system, which can in turn require increased flexibility (see Ela et al. forthcoming). Although certain changes to short-term energy and ancillary service markets may be needed to ensure that the available flexibility is offered to the market, this may not guarantee that sufficient flexibility is built or available in the first place. This could lead to the need for new ways in which resource adequacy evaluation is performed and subsequently modified revenue sufficiency mechanisms.

Finally, VG has total costs that are almost entirely fixed capital costs rather than variable operating costs. As a result, VG units are likely to offer energy at near-zero, zero, and negative-bid costs, which can reduce both the average energy prices and the cleared energy levels of existing generating plants. This could lead to further reliance on markets or incentives in addition to the energy market to ensure that the resources needed for long-term reliability can recover both variable and fixed capital costs.

4.1 Calculating the Capacity Value of VG

VG is unique in its dependence on diurnal and seasonal weather patterns for capacity availability. This factor has a more substantial impact on capacity value (ELCC) than FOR has on conventional generation's capacity value. The capacity value calculation for VG is essentially the same as that described above for conventional power plants, but rather than relying on FORs, load and VG production data (real or simulated, depending on data availability and the specific study requirements) are used to calculate the fraction of VG capacity that contributes to resource adequacy. Ideally, the VG data are time-synchronized with load to capture important weather related correlations (e.g., Milligan and Porter 2008; IEA Wind 2013; Keane et al. 2011). Details about the method can be found in Keane et al. (2011).

The ELCC of wind power plants typically ranges from approximately 5% to 40%, depending on the method employed and the geographic region considered (Keane et al. 2011). Many areas approximate the capacity value of VG based on certain metrics (median generation value or average capacity factor) during a specified subset of hours in a given year, as indicated in Table 4.

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Table 4. Methods for Determining the Capacity Value (ELCC) of Wind and Solar in RTO/ISO Capacity Markets (Ela et al. 2014)

RTO	Season	Months	Time	Term	Method
ISO-NE	Summer	June–September	1 p.m.–6 p.m.	5-year rolling	Medium net generation
ISO-NE	Winter	October–May	5 p.m.–7 p.m.	5-year rolling	Medium net generation
ISO-NE	All	Default based on summer and winter wind speed data and ISO oversight			
NYISO—Existing	Summer	June–August	2 p.m.–6 p.m.	Previous year	Average capacity factor
NYISO—Existing	Winter	December–February	4 p.m.–8 p.m.	Previous year	Average capacity factor
NYISO—New Onshore Resources	Summer	10% default capacity credit			
NYISO—New Onshore Resources	Winter	30% default capacity credit			
NYISO—New Offshore Resources	All	38% default capacity credit			
PJM	All	June–August	2 p.m.–6 p.m.	3-year rolling	Average capacity factor
PJM—New Wind	All	13% default capacity credit			

However, the use of predefined peak windows has historically been determined to be inadequate for identifying periods of risk. As such, this practice provides an incomplete picture of the state of reliability of the generation fleet (Rogers and Porter 2012, Milligan et al. forthcoming). This shortcoming can be overcome by identifying the highest load hours using a ranked order approach or identifying periods of time during which there is (or may be) high LOLE. NYISO and PJM have incorporated the latter approach into their methods for determining the capacity value of wind energy (Table 4). As described in Porter et al. (2012), these approaches calculate the capacity factor of the wind resource during the critical time periods and use that as a proxy for the capacity value. In some cases, such as in GE (2005), the capacity factor may match the more rigorous ELCC fairly closely, but this is not guaranteed. One example of inconsistent matches was shown in Shiu (2006), which evaluated the capacity value (ELCC) of wind and solar generation for a three-year period. Figure 3 summarizes a comparison of ELCC values (solid bars) among three wind power plants and one solar power plant along with the capacity factors (hatched bars) of these respective plants calculated during the peak period, defined from June to September, 12:00 p.m. to 6:00 p.m. The solar values are calculated during the daytime when demand is generally high, resulting in the larger overall CF values compared to wind.

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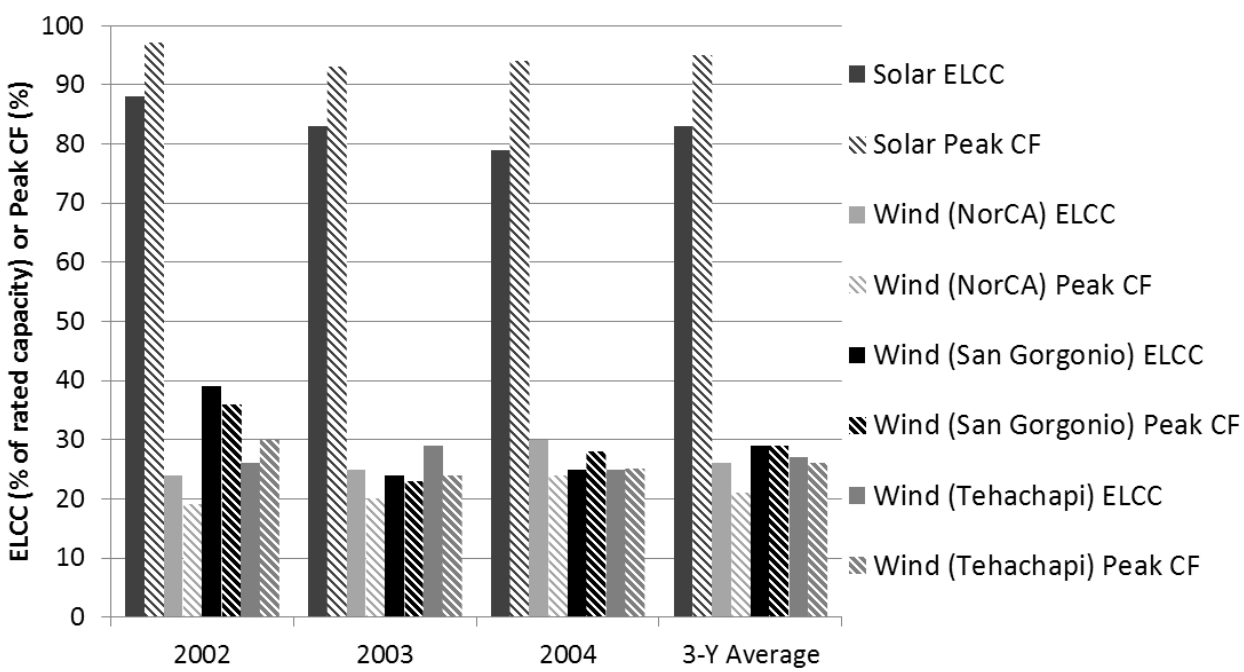

Figure 3. ELCC does not always match peak-period capacity factors (adapted from Ela et al. 2014)

The implication of these results is that unless the ELCC is used to identify a suitable peak window for calculating a time-period capacity factor, a system that relies on the latter to quantify the capacity value of VG may have difficulty achieving reliability targets. This is not surprising, because there is no specific reliability information contained within capacity factors despite the possibility that high-risk (high-LOLP) hours generally correspond to peak periods.

Thus, it may be useful to consider ELCC itself as a candidate metric for a capacity/resource adequacy market, because it would better capture a resource's contribution to reliability than current metrics such as UCAP. However, there are several challenges to implementing such a probabilistic metric. ELCC is highly nonlinear and potentially sensitive to several other influences. More work would be needed to develop an ELCC-based metric that would be directly exchanged in capacity markets. As an alternative, more rigorous mapping between ELCC and UCAP or a similar metric may result in achieving the goal of retaining some reliability information in the market yet perhaps overcome some of the concerns regarding the nonlinearity and other issues, such as sensitivity to ordering, that may exist.

4.2 Incorporating Flexibility into Resource Adequacy Needs

VG contributes to long-term reliability needs not only because of its weather-driven capacity availability as just discussed, but also because of the increased need for system flexibility due to their variability and uncertainty. This latter issue focuses on how much and what type of generation to build. Incentivizing the development of sufficient flexible resources is a prerequisite to utilizing that flexible generating asset in market operations.

Many new methods, some that are very similar to those developed previously for capacity valuation (i.e., LOLE and ELCC), are being developed to better understand long-term flexibility needs. One approach to extend the traditional resource adequacy techniques to flexibility analysis is a modified LOLP analysis, which is based on the changing levels of load and

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generation. Lannoye et al. (2010) developed a method to meet this goal by focusing on how rapidly a resource can respond to an instruction. Figure 4 from this study shows how standard LOLP-related metrics map to ramping. The adaptation makes it possible to apply the same underlying methods from LOLP, ELCC, and related reliability metrics to ramping because a generator's ability to ramp will depend in part on whether it is on forced outage. Generators that have high FORs will have a lower effective ramping capability compared to a unit that has a low FOR, all else equal. A related approach to accounting for flexibility needs within the resource adequacy framework has been implemented by Astrape Consulting. They have broken the LOLE metric into components which are due to capacity inadequacy and flexibility inadequacy as reflected by generation ramp limits on both sub-hourly and multi-hourly timescales (Carden 2015).

Another method to determine flexibility needs is to use time-synchronized load and VG data to evaluate different metrics of the net load ramp magnitude and timing. Examples of these metrics include averages by season or time of day and maximum ramp magnitudes and durations by different probability envelopes (see example in Figure 5).

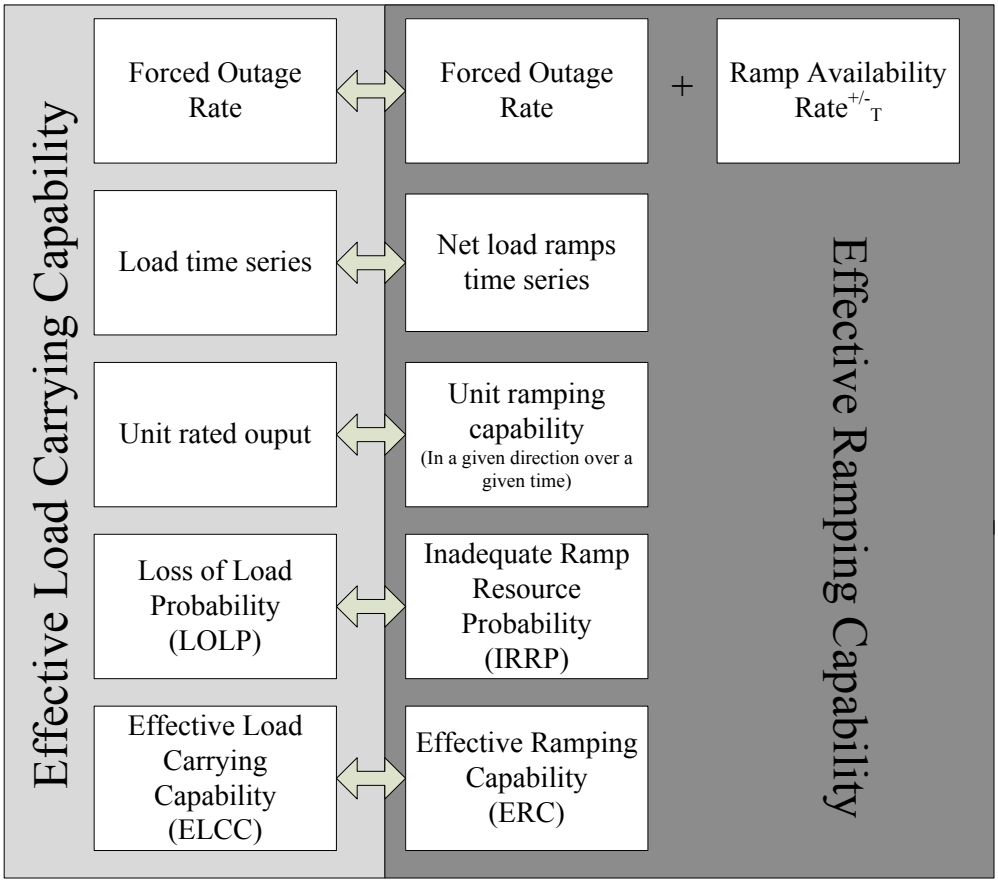

Figure 4. Proposed metrics to understand how ELCC can be similarly adapted to understand the capability of resources to meet expected flexibility needs (Lannoye et al. 2010)

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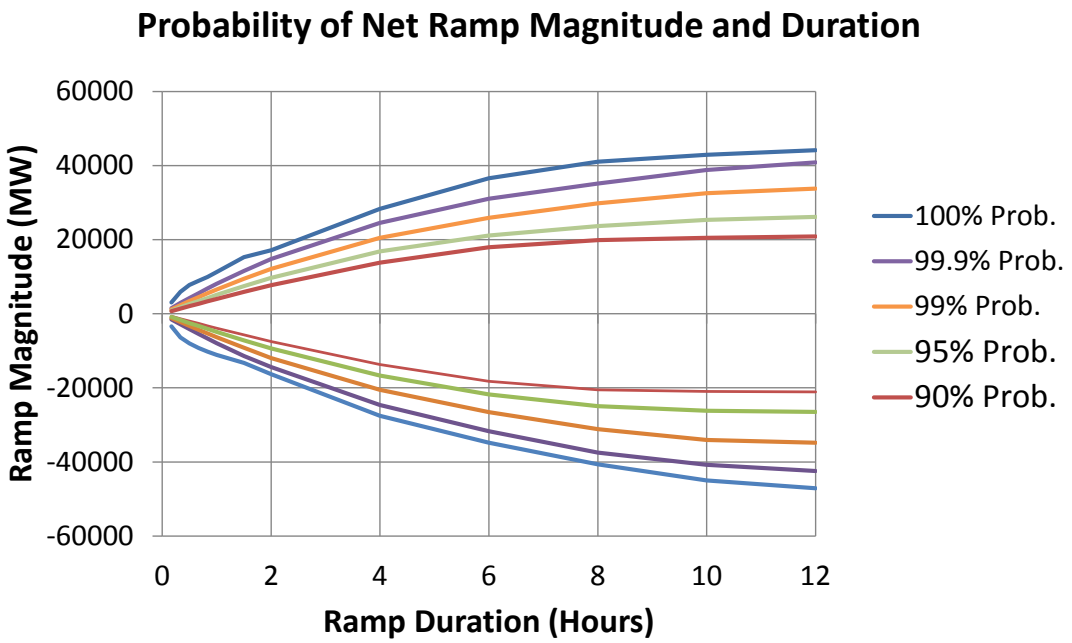

Figure 5. Ramp envelopes can be used to obtain a view of long-term flexibility needs (King et al. 2011)

4.3 Revenue Sufficiency Challenges as a Result of Increased Amounts of Low-Variable-Cost Resources

New electricity market entrants with very low variable costs create revenue sufficiency challenges for marginal units. Because unit commitment and economic dispatch are based on variable costs, market participants that bid low costs decrease the LMP and displace more expensive units, reducing the capacity factors of these units. This has been clearly documented with changes in natural gas prices,[2] and it has been observed with VG. Empirical evidence from regions that have high penetrations of wind generation indicates that the low marginal cost of wind generation may decrease LMPs and thus reduce revenue of all suppliers in the energy market (Maggio 2012). Other studies have observed similar price suppression and capacity factor reduction results (Lew et al. 2013, Levin and Botterud 2015; Bloom et al. 2015).VG can also cause more occurrences of zero or negative LMP periods because of its bid costs. These outcomes can affect the revenue stream of other resources that may depend on revenue from the energy market, preventing them from recovering both variable and fixed costs. This impact of wind power on market prices is not confined only to the United States; it has been apparent in other countries as well (Milligan et al. 2012).

Increased penetrations of VG can cause LMPs to be more volatile from one time period to another because of the limited predictability of wind and solar output. This creates uncertainty regarding LMPs that can be expected in a market due to the inherent variability of VG and inability to precisely predict its output. This can cause price divergence between DAM and RTM LMPs.

The question is what the combination of lower energy prices and lower capacity factors of existing plants implies for revenue sufficiency. It may be possible that even though the majority of prices are being depressed, the occasions of high price spikes may increase, helping to capture

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needed revenue. This may depend, however, on price caps, market mitigation procedures, and the price levels of administratively-set scarcity pricing. Finally, the existence and design of forward capacity markets can have a large impact on the level of revenue sufficiency.

4.4 Revenue Sufficiency Challenges as a Result of Increased Flexibility Needs

Initial evidence suggests that high penetrations of VG will require increased levels of flexibility to manage increased net load variability and uncertainty. It is unclear whether or not the current market designs have the right incentives to provide this flexibility, potentially leading to reliability issues or costly out-of-market actions. There are two main groups of potential market structures that can incentivize investment in new flexible resources, and both focus on long-term investments in flexibility. First, markets could be designed to provide incentives for new resources entering the market to have the flexibility attributes that are needed. Second, markets could provide incentives for existing resources to increase their ability to provide flexibility (e.g., through retrofits), subject to technical barriers and economic trade-offs.

There is no widespread agreement about whether volatile energy prices will induce suppliers to invest in the needed level of flexibility or whether an explicit market for flexibility is required. Another open question is whether existing capacity markets (with or without modifications to better capture resource adequacy aspects) should be conducted in tranches of differing flexibility requirements or whether there should be separate, linked markets for capacity (resource adequacy) and flexibility. Adding to these complications is that the electric power system is not in a steady state; it is in a transition between a low-VG past and a potentially high-VG future. Thus, it is unlikely that current price signals can provide a good indication of the flexibility requirements 5 or 10 years from now. Therefore, investors in flexibility will need to determine the required level of flexibility throughout the lifetime of potential new flexible technologies.

5 Traditional Market Designs to Ensure Resource Adequacy and Revenue Sufficiency

Two approaches have been adopted by regulators to ensure that opportunities exist to recover fixed capital costs. As discussed in Section 3, these administrative mechanisms exist because of the inelasticity of demand and monopolistic tendencies of electricity supply. First, scarcity pricing, typically based on administrative price caps, may allow prices that exceed the variable costs of the most expensive operating resources for short periods of time when capacity or reserves are scarce so that those prices can help recover the fixed costs of the peaking units in addition to addressing the short-term reliability need. The second mechanism, a forward capacity market, is part of three U.S. wholesale electricity markets (PJM, ISO-NE, and NYISO). These markets look ahead to ensure that enough available capacity will be installed and available to meet load in peak periods and aim to provide incentives for new capacity to be built in locations where it is most needed.

5.1 Scarcity Pricing

Scarcity pricing[3] allows the energy and/or ancillary services prices to greatly surpass the variable cost of the highest variable-cost resources when the system is capacity constrained. Because

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consumers are generally not price responsive due to the market design flaws discussed in Section 2, systems operators must instead use out-of-market actions to avoid shortage conditions. These actions include value of lost load (VOLL) pricing, ancillary service scarcity pricing, and emergency demand-response pricing. The VOLL is an estimate of the potential cost of supply shortages when load must be involuntarily curtailed. The VOLL and associated administratively-set scarcity prices are typically very high because of the large economic losses that are usually associated with outages, such as food spoilage, failure of expensive industrial processes, etc. These prices vary significantly throughout the United States. Energy shortage prices, which are often set to the VOLL and may or may not include price penalties from ancillary service products, range from thousands to tens of thousands of dollars per MWh (Table 5).

Table 5. Energy Scarcity Pricing for Selected U.S. Energy Markets (adapted from FERC 2014a and 2014b). MCP=Market Clearing Price

	Price ($/MWh)	Pricing Type
CAISO	1,000	Maximum energy offer cap
SPP	50,000	Maximum LMP (accounts for all shortage-priced reserve product MCPs)
NYISO	1,000 (up to possible 2,775 with reserve constraint penalties)	Maximum energy offer cap
ISO-NE	1,000 (up to possible 2,350 with reserve constraint penalties)	Maximum energy offer cap
MISO	3,500	Maximum LMP (system-wide and including all operating reserves) set to VOLL
PJM	1,000 (up to possible 2,100 with reserve penalties, which occurs when calling on emergency demand response)	Maximum energy offer cap
ERCOT	9,000	Maximum LMP (system-wide and including all operating reserves) set to VOLL

In typical power system operations, shortages will first result in insufficient reserve capacity while load balance is maintained. Therefore, in practice, scarcity prices are typically dependent on administratively-set *ancillary service* scarcity prices, which can be based on pre-set price curves or more dynamic, system-based conditions (Table 6). In systems that co-optimize energy and reserves, these administratively-determined ancillary service scarcity prices will set the price for both operating reserve and energy when the system is short of reserve because it means that there is an overall capacity shortage (or ramping capability shortage). These prices spikes, when triggered with a frequency that corresponds to the system reliability target, help resources generate sufficient revenue to recover their fixed costs. Sometimes the administratively-determined ancillary service scarcity prices use the VOLL in its calculation so that VOLL is still reflected in the resulting prices. Research studies have looked at many new ways of incorporating VOLL in the ancillary service pricing explicitly (Wang, Wang, and Wu 2005; Ortega-Vazques and Kirschen 2007), accounting for the probability of not being able to meet load (e.g., Hogan 2005, Zhou and Botterud 2014).

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Table 6. Administratively-Set Ancillary Service Scarcity Prices for Selected U.S. Markets (Ela et al. 2014)

Market	Regulation	Spinning Reserve	Total Contingency	Other
NYISO[a]	• $400 if scarcity is greater than or equal to 80 MW • $180 if scarcity is between 25 and 80 MW • $80 if scarcity is less than 25 MW	• $500[b]	• $450[b]	30-min reserve[b] • $200 if scarcity is greater than or equal to 400 MW • $100 if scarcity is between 200 MW and 400 MW • $50 if scarcity is less than 200 MW
ISO-NE[c]	• N/A	• $50	• $850	30-min operating reserve[d] • $500
MISO[e]	• Monthly peaker proxy price[f]	• $98 if scarcity is greater than 10% of requirement • $65 if scarcity is less than 10%	System-wide operating reserve[g] • Min: $1,100 • Max: VOLL-RegDC	• N/A
CAISO[hi]	Regulation up • $200 Regulation down • $700 if scarcity is greater than 84 MW • $600 if scarcity is between 32 and 84 MW • $500 if scarcity is less than or equal to 32 MW	• $100	• $700 if scarcity is greater than 210 MW • $600 if scarcity is between 70 MW and 210 MW • $500 if scarcity is less than or equal to 70 MW	• N/A

[a]NYISO Market Services Tarriff. Accessed May 2014: http://www.nyiso.com/public/markets_operations/documents/tariffviewer/index.jsp.
[b]These numbers represent statewide scarcity prices. Locational scarcity prices exist for Eastern and/or Long Island spinning reserve as well, but they are not shown here.

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[c]ISO-NE Market Services Tariff, Section III – Market Rule 1. Accessed May 2014: http://www.iso-ne.com/regulatory/tariff/sect_3/.
[d]These results represent the system-wide 30-minute operating reserve. Local rules exist for this product as well, but they are not shown here.
[e]MISO Business Practices Manual-002, Energy and Operating Reserve Markets. Accessed May 2014: https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx.
[f]The monthly peaker proxy price is equal to the average cost per MW of committing and running a peaking unit for an hour. The price is updated on a montly basis.
[g]The scarcity price for operating reserve is determined based on the product of VOLL and the conditional probability that a resource contingency will occur. The minimum price of $1,100 is set based on the sum of the energy and reserve offer price caps ($1,000+100). The maximum price is set based on VOLL (~$3,500) minus the regulating reserve demand curve price.
[h]CAISO, Final Draft Proposal: Reserve Scarcity Pricing Design. Accessed May 2014: http://www.caiso.com/Documents/DraftFinalProposal-ScarcityPricing05-Oct-2009.pdf.
[i]The scarcity prices depend on the bid cap. The numbers presented here assume a $1,000 bid cap. A lower bid cap would result in lower scarcity prices.

In practice, the uncertainty and volatility of scarcity price events makes investing in new generation capacity difficult and risky. VG may cause a higher probability of scarcity events due to its increased variability and uncertainty. Depending on how it is implemented, scarcity pricing may directly link reliability to economics. For example, a price cap may be established so that it corresponds to a target LOLE, LOLH, or EUE. Prices based on demand response bids can provide a similar effect, but in this case the consumers' willingness to pay for electricity is directly reflected in the bid prices.

5.2 Forward Capacity Markets

Forward capacity markets have been put in place to establish more certain revenue streams for investments in new capacity that will be needed at a future date. These markets determine capacity prices depending on the current supply of capacity and the RTO's/ISO's predicted capacity requirements. Capacity markets are often backstop mechanisms that evaluate potential capacity shortfalls after considering bilateral contracts or other power purchase agreements. The capacity markets vary with respect to the time horizon for which they are securing capacity, the resource qualification criteria (e.g., how demand response and other nontraditional technologies can participate), and the slope of the demand curve. Securing capacity over a shorter forward period can provide a challenge because it may not be long enough to adequately stimulate the necessary investment and construction time. A common concern expressed by stakeholders and in the literature is whether and how to differentiate compensation for capacity among different capacity types and ages (Jenkin et al. forthcoming). The forward capacity markets also usually have zonal markets, such that new capacity is incentivized to locate and be able to deliver power in areas that need that capacity the most.

Administrative price caps are typically used to limit capacity prices to the cost of new entry (CONE), which is usually set to the annualized capital cost of a peaking plant. Price floors may also be in place to avoid price collapse and the potential exercise of market power from purchasers of capacity (Cramton and Ockenfels 2012, Miller et al. 2012). Figure 6 illustrates the main principles of a demand curve that is constructed around a target for new capacity at which the price is set to the CONE, although we note that there is ongoing debate across different U.S. markets over the value and shape of such demands curves, as well as the choice of the reference technology and cost-basis for the CONE (Jenkin et al. forthcoming).

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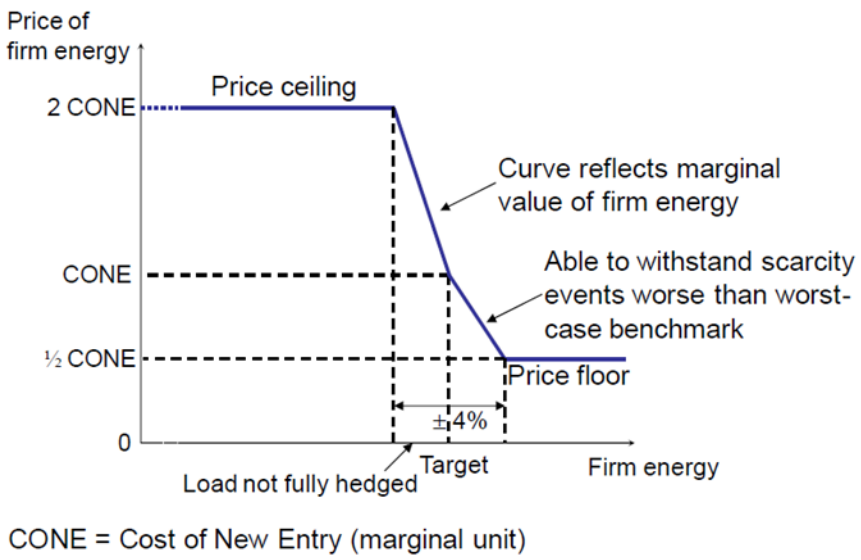

Figure 6. Illustration of demand curve for capacity (Cramton and Ockenfels 2012)

Two aspects of generator performance may be relevant for capacity markets. The first aspect relates to the capability that the unit can provide in terms of ramping, minimum up/down times, and generally flexible operations. It is likely that an increase in renewable generation will increase the need for flexibility in the system, as discussed in Section 4.

The second aspect of generator performance is how the unit responds as a capacity resource during the critical system times, as discussed in Section 3.1. Generally, this is defined by a resource's delivered capacity (UCAP)—i.e., accounting for a resource's likelihood of forced outage at a certain time—as opposed to ICAP. However, each U.S. market handles this capacity distinction differently. For example, forward capacity markets in PJM and NYSIO are based on UCAP, while ISO-NE uses ICAP (Pfeifenberger et al. 2013). The linking of the capacity market to a reliability metric by using UCAP provides more meaning and consistency in the accounting of system reliability, and it results from the absence of total price transparency from generation to end user. Recent changes have also seen more specific performance-based capacity products (ISO-NE 2015, PJM 2015).

The size and composition of the jurisdiction that establishes and operates the capacity market, along with the rules for how and what capacity counts toward the target, may have significant impacts on long-term system reliability. As shown by Ibanez and Milligan (2012), additional capacity value can be acquired via aggregation: the combined capacity needs of a pooled area will often be lower than the total required capacity needed in each individual area. Therefore, resource adequacy assessments, even when considered on a reliability basis, are affected by the level of aggregation used when establishing the appropriate capacity target and crediting load-serving entities for capacity acquired via power purchase or other mechanisms. This means that the market may incorrectly assess the quantity and price of new capacity unless a regional (such as within an RTO) target is developed first and then allocated to the appropriate load-serving entities.

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6 Evolving Market Designs to Ensure Resource Adequacy and Revenue Sufficiency

Electricity markets have recently started to incorporate new designs to address some of the issues with resource adequacy and revenue sufficiency. Two changes are discussed here. The first approach, taken by ERCOT, relies on price incentives in short-term markets for energy and reserves to ensure capacity adequacy and revenue sufficiency. A second approach, taken by CAISO, relies on administrative and centralized planning procedures to ensure both the amount of future capacity and level of flexibility in the future resource mix. More details about the changes in these regions can be found in Ela et al. (2014).

6.1 ERCOT

In ERCOT, which is the only electricity market in the United States that relies on an energy-only market design to ensure capacity adequacy, recent changes have been made to the way in which scarcity prices are calculated. First, the offer cap that limits the bid price of generation resources is gradually being increased up to $9,000/MWh so that that energy prices can increase during periods of extreme scarcity. Second, a dynamic operating reserve demand curve (ORDC) has been implemented in the real-time market such that the price of the curve will depend on the hourly LOLP, which depends on the amount of operating reserve available (Hogan 2012). Ideally, the ORDC should be used to co-optimize the provision of energy and reserves. However, because there is currently no co-optimization of energy and reserves in the ERCOT real-time market, a post calculation that mimics co-optimization and derives prices for reserve is used instead (Hogan 2013). This operating reserve price is added to the energy price as a direct premium so that the additional revenue may help recover fixed costs.

Figure 7 compares the proposed ORDCs for four different seasons to the current practice of using a fixed reserve requirement and scarcity price, which is equivalent to a vertical demand curve (in black). The downward-sloping demand curves will result in higher prices whenever the reserve margin is below the current requirement of 3,300 MW, but it may actually give lower prices when the reserve level is above 3,300 MW.

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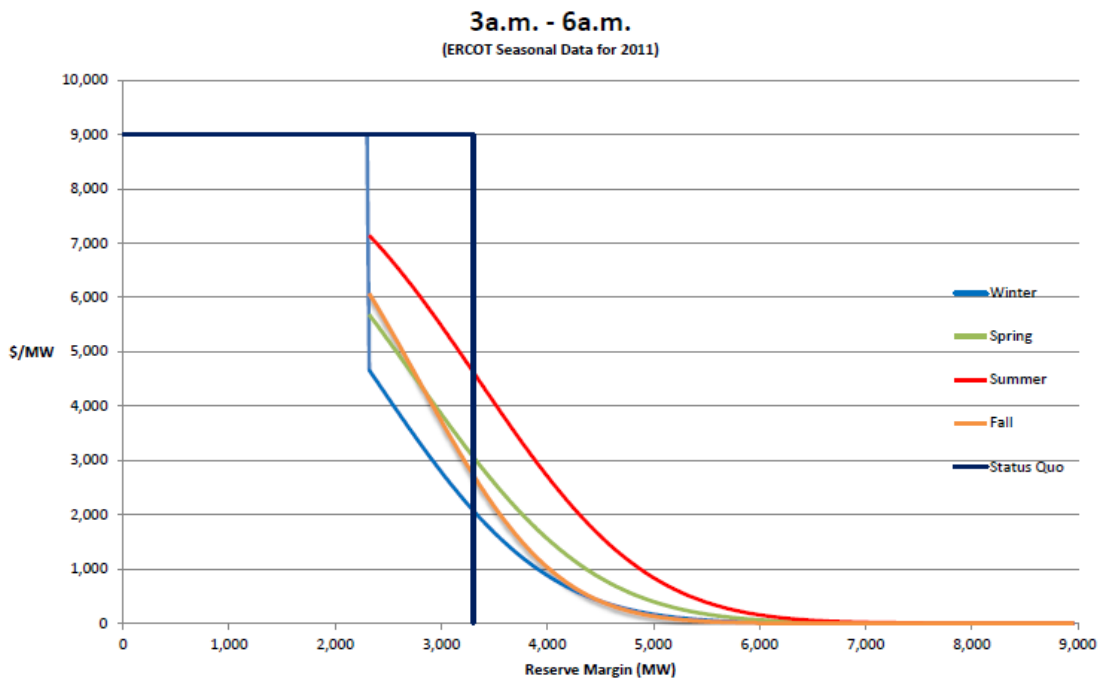

Figure 7. Illustration of ORDCs for different seasons in ERCOT for the time period from 3 a.m. to 6 a.m. based on data from 2011 (Anderson 2013)

6.2 CAISO

A recently approved tariff revision in CAISO will require load-serving entities to not only procure sufficient capacity to meet forecasted peak load but also to meet additional flexibility requirements within their capacity mix (CAISO 2014 and 2015). This is the first U.S. market area to include flexibility attributes in its resource adequacy planning requirements. Under this new rule, any resource that contributes to meeting the flexibility requirement must offer a flexible resource in the short-term energy markets (DAM and RTM). The flexibility requirement is based on the maximum 3-hour upward net load ramp that is projected to occur in a month, but proposed extensions to this rule may enforce shorter-duration ramping requirements, among other considerations (CAISO 2015).

7 Summary

Designing a market that ensures the reliability of supply—resource adequacy—is a difficult proposition. The large-scale expansion of VG adds further complexities to resource adequacy assessments and the challenge of designing markets to ensure revenue sufficiency. Due to their low marginal costs (and bid costs), VG resources depress energy prices and also reduce the energy schedule of existing generators, thereby lowering the revenue and capacity factor of those units. These impacts exacerbate the revenue sufficiency challenge of ensuring sufficient opportunity for generators to recover both their fixed and variable costs. Insufficient revenue may lead to an unreliable system when existing resources choose to leave the market, or new resources choose not to enter, due to uncertainty over their long-term profitability. Reliability issues can also arise from miscalculations of the long-term reliability need, both for capacity and other attributes. We have reviewed several historical approaches taken by power markets in the

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United States to manage these issues, described how these approaches have evolved in recent years, and discussed how the current markets function and manage the various challenges of VG. These issues are now being addressed by many regions, although there are differences in approaches. It is still an open debate whether current market designs can provide the incentives that are needed to ensure adequacy in the long run or if new approaches are needed.

We also provided an overview of reliability metrics that are used to assess resource adequacy. Probability-based metrics such as LOLE are common in many regions of the United States, although PRM is still widely used. We have shown that the PRM can be an inadequate tool for measuring reliability because it is based only on capacity and ignores data regarding FOR. This is especially true for systems that have high penetrations of resources with low capacity values. Although it is possible to calculate the PRM that would result in a given LOLE target, which is done by some markets, the value of the PRM metric is still questionable because it can no longer be used to compare different systems, nor does it provide consistent information regarding resource adequacy.

There is growing interest in whether and how flexibility should be incorporated into the resource adequacy process, especially as more VG is added to the system. Determining the precise mechanisms that can ensure resource adequacy along with the required long-term levels of flexibility is an active area of research. A clear market signal is needed to communicate future flexibility requirements to investors. A current proposal in CAISO would establish the first-of-its-kind flexibility requirement based on the projected system ramping needs in the short-term markets.

Two distinct directions in terms of market designs for long-term resource adequacy and revenue sufficiency have emerged: (1) forward capacity markets and (2) scarcity pricing in energy-only markets. In our discussion of capacity market mechanisms from a reliability standpoint, we showed the difficulty in using peak periods as a proxy for times of system risk and the difficulty of the ability of a capacity market to capture the salient aspects of resource adequacy and reliability. The regions in the United States that have capacity markets have alternative ways of mapping the reliability target to the capacity acquisition target, though there are significant differences in market timing and questions about the ability to capture the long-term investment process to ensure adequacy. Although it may be useful to consider ELCC as a candidate metric for a capacity/resource adequacy market, ELCC is not a transparent metric and may result in order-sensitive differences in capacity contribution; thus, more work is needed to determine whether it is a suitable metric for a market.

If electricity market designs rely on the energy-only approach, the key challenge is to ensure that the short-term prices for energy and reserves provide sufficient incentives for investments in a resource mix with sufficient capacity and flexibility. Appropriate scarcity pricing has been and still is the main solution for revenue sufficiency in an energy-only market. This will require clever regulatory market interventions that allow prices to rise during scarcity conditions without creating opportunities for market manipulation. It is an open question whether future prices for energy and reserves will adequately compensate ramping capabilities to meet system flexibility needs as well as the required need for available capacity. Recent changes in the energy-only ERCOT system attempt to address these concerns by increasing the scarcity pricing and raising average energy prices through a dynamic operating reserve cost curve.

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It is important that further research is carried out to ensure that evolving market designs are providing the incentives they set out to provide and can achieve optimal efficiency and reliability. We believe that the industry will go through several iterations before consensus emerges on the specific best practices for these complex topics of resource adequacy and revenue sufficiency in electricity markets that have large-scale penetrations of renewable resources.

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[1] One example is NYISO, which calculates the planning reserve requirements based on ICAP but then translates those values, by region and resource type, to UCAP for use in the UCAP-based capacity market (Potomac Economics 2015).

[2] For example, the dramatic decrease in the cost of natural gas in 2008, coupled with low load growth, decreased LMPs in most U.S. energy markets.

[3] The terms "scarcity pricing" and "shortage pricing" are usually used interchangeably. See (FERC 2014a) for more discussion and exceptions to this general rule.

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