Resource Adequacy for the Energy Transition: A Critical Periods Reliability Framework and its Applications in Planning and Markets

August 2025

Energy+Environmental Economics

This paper is prepared by:

Zachary Ming

Nick Schlag

David Delgado

Aaron Burdick

Kevin Steinberger

Ben Elsey

Ari Gold-Parker

Adrian Au

Charles Gulian

Arne Olson

E3 would like to thank the following reviewers, who provided valuable input on this paper. Their participation does not imply endorsement.

Debra Lew and Erik Ela, Energy Systems Integration Group

Matt Barmack, Calpine

Jacob Mays, Cornell University

Derek Stenclik, Telos Energy

Rob Gramlich, Grid Strategies

Keith Parks, Xcel Energy

Table of Contents

Figures

1 Introduction

Resource adequacy is an increasingly important topic in electricity system planning and markets. Unprecedented load growth, changes in historical weather patterns, retirement of significant quantities of conventional resources, and the increasing prevalence of variable and energy-limited resources have created mounting challenges for ensuring resource adequacy. At the same time, conventional thermal generators have performed below expectations during highly-scrutinized recent winter storm events.[1] It is increasingly apparent that longstanding practices for determining total resource need, allocating need among load-serving entities ("LSEs"), quantifying the ability of resources to contribute to meeting reliability need, and verifying resource performance are no longer up to the task of assuring an adequate power system in the future. A burgeoning academic and informal literature addresses various aspects of these challenges,[2] and several market operators in the United States have introduced reforms in their capacity accreditation methods.

This paper lays out a conceptual framework for modernizing resource adequacy analytics and their applications in electricity system planning and wholesale electricity markets. Building on conventional loss-of-load-probability ("LOLP") modeling, we describe a **"critical periods"** reliability framework that identifies the conditions in which power systems are most likely to suffer from supply shortfalls and incentivizes investment to meet changing needs in the most economically efficient manner. We describe how this framework ties together the critical engineering objective of ensuring reliable electric service during all hours of the year and the economic objective of sending appropriate price signals to encourage efficient capital allocation.

The key feature of the critical periods reliability framework is a reorientation of all aspects of resource adequacy planning away from an exclusive focus on *peak demand periods* and toward a focus on *critical periods* when a loss-of-load event is occurring or imminent. Both loads and resources are evaluated based on the **marginal impact** of their actions on system reliability. By focusing on conditions during critical periods, this framework identifies and compensates actions such as new generation investments or voluntary load reductions that directly reduce the probability of lost load.

This shift is not as significant a departure from traditional practices as it might seem; historically, the most critical periods for electric reliability have been during severe hot or cold weather events that cause the highest electric demand. However, with higher penetrations of variable and energy-limited

[1] PJM Interconnection. *Winter Storm Elliott Event Analysis and Recommendations*. July 17, 2023. https://www.pjm.com/-/media/DotCom/library/reports-notices/special-reports/2023/20230717-winter-storm-elliott-event-analysis-and-recommendation-report.pdf.

[2] N. Schlag, Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, and H. Jiang, "Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy," Energy and Environmental Economics, Inc., August 2020. https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf. Johannes Pfeifenberger et al. "A Resource Adequacy Framework for the Evolving Power System." *IEEE Power and Energy Magazine* 19, no. 3 (2021): 55–63. https://ieeexplore.ieee.org/document/9473022. Energy Systems Integration Group. *New Criteria for Resource Adequacy*. March 2024. https://www.esig.energy/wp-content/uploads/2024/03/ESIG-New-Criteria-Resource-Adequacy-report-2024.pdf.

resources, low electricity supply conditions will be increasingly important drivers of critical periods. Thus, a focus on critical periods is a natural adaptation of, and is in fact a generalization of, traditional practices in recognition of changing electricity system dynamics.

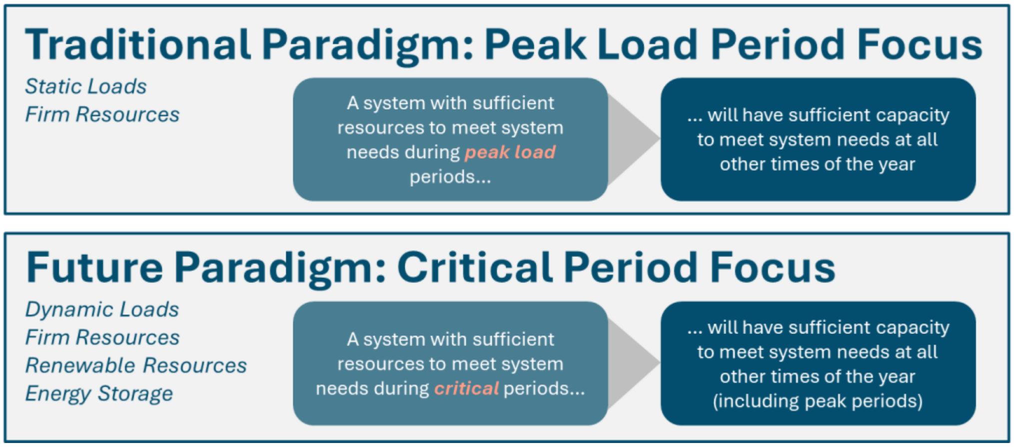


Figure 1: *A changing paradigm for ensuring resource adequacy*

Most independent system operators ("ISOs") and many electric utility planners are already adopting some of the features of the critical periods reliability framework described in this paper. However, there continues to be a need for clear understanding of the underlying engineering and economic fundamentals for measuring resource adequacy needs and appropriately compensating actions that contribute to meeting them. Moreover, utilities and ISOs can continue to improve their practices through diligent application of additional aspects of the critical periods framework. This paper lays out a comprehensive vision of this framework, identifies its physical and economic benefits, and provides detailed recommendations for its implementation in both the planning and market contexts.

2 Background

2.1 Origins of Modern Resource Adequacy Planning

The foundation for modern resource adequacy planning was established in the middle of the twentieth century when widespread use of computationally intensive methodologies first became practical. At that time, the majority of generating resources could be considered "firm," meaning they were able to produce power at full capacity at any time for sustained periods, unless out of service due to maintenance or forced outage. Because most resources were available at any given time, the periods of highest reliability risk were periods of **peak load** when demand could exceed the aggregate capability of all generating resources, as illustrated in the figure to the right.

To measure reliability risk, planners developed LOLP models that evaluate the ability of a portfolio of power plants to serve load across a broad range of weather conditions and generator outage states.[3] Combining these yields the statistical likelihood that supply might be insufficient to meet demand.

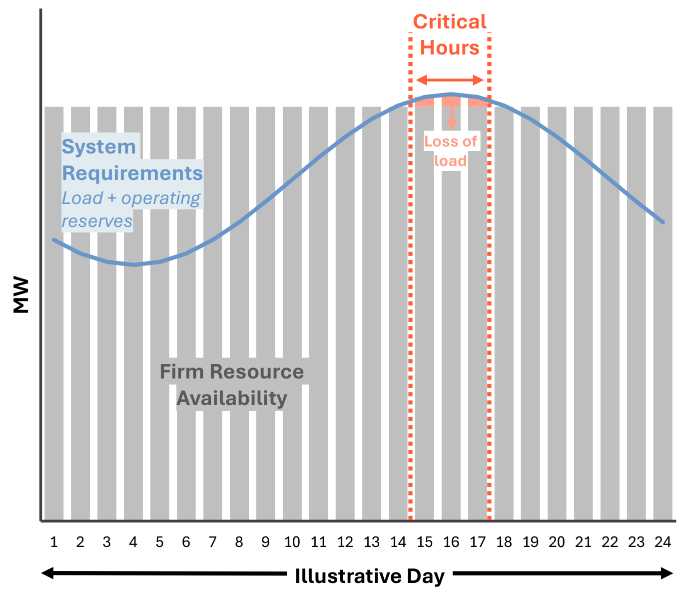


Figure 2: *In traditional power systems, critical hours almost always coincided with highest demands*

Today, LOLP modeling is the primary method used for evaluating the need for power system resources. Adding resources reduces the frequency, duration, and magnitude of loss-of-load events; the quantity of resources needed to meet a specified loss-of-load standard is the Total Reliability Need. This has historically been simplified into a planning reserve margin ("PRM") framework: a planning requirement to maintain a margin of capacity above expected peak load to account for (1) the potential for higher loads than expected, (2) the possibility of generator failures, and (3) the need to maintain a minimum level of operating reserves even under energy emergency conditions to avoid the potential for cascading outages. While PRM requirements naturally vary from one system to another due to each system's unique characteristics (and, increasingly,

In a traditional system where most resources were firm, a system operator that could maintain reliability during peak load could also maintain reliability during all other times as well

[3] Roy Billinton and Ronald N. Allan, *Reliability Evaluation of Power Systems*, 2nd ed. (New York: Plenum Press, 1996).

inconsistent accreditation methods), commonly observed values are 15-20% above median peak demand on an “installed capacity” (“ICAP”) basis.

For decades, this framework provided a simple, transparent, and robust approach to ensuring resource adequacy. Because power systems relied mostly on firm resources, a system that maintained a PRM sufficient to serve load reliably during the peak load hour would also serve load reliably during all other times of the year. And because resources were generally alike in their ability to operate during peak demand conditions, differentiating their reliability contributions was either unnecessary or could be done outside of a rigorous loss-of-load modeling framework (such as through adjustments for resource-specific outage rates).

In the 1990s and 2000s, as organized wholesale electricity markets arose, this same approach was adapted for use in the design of capacity markets and resource adequacy pooling programs. These programs used the same basic principles to establish three key elements of capacity market design:

- **(1)** Need determination, how much total capacity is needed across the pool to meet the resource adequacy standard,
- **(2)** Capacity accreditation, how much each individual resource can be counted towards that requirement, and
- **(3)** Need allocation, how much responsibility each individual LSE bears for the requirement of the system.

While organized wholesale markets provide for electricity supply and demand to be settled at hourly-varying market-clearing prices, there are structural barriers that prevent these markets from identifying and supplying the economically optimal level of resource adequacy. As a result, hourly energy markets on their own have been insufficient in many markets to incentivize the development of new resources and the retention of existing resources. Capacity markets were developed to remedy the resource adequacy “externality” and provide a means for resource owners to recover the “missing money”[4] – the cost of developing new resources minus the revenues those resources can earn in the energy and ancillary services markets. The primary goal of these markets is to procure the economically efficient quantity and mix of capacity to meet the resource adequacy standard. Meeting this goal requires sending efficient signals for both (1) resource accreditation – to provide the appropriate incentives to resource developers for adding capacity to the system, and (2) need allocation – to provide appropriate incentives to LSEs regarding the cost of increasing or reducing electricity demand. The capacity constructs adopted by organized markets met these principles by determining and allocating need based on peak demand.

[4] Todd S. Aagaard and Andrew N. Kleit, "Reliability and the Missing Money Problem," in Electricity Capacity Markets, Cambridge University Press, 2022, pp. 37–53. https://www.cambridge.org/core/books/abs/electricity-capacity-markets/reliability-and-the-missing-money-problem/965E1DD6466BFD7C1CE8F8FF62EB745C.

2.2 Evolving Resource Adequacy Challenges

2.2.1 Shifting Net Peak Load

In the 2000s, as the quantities of wind, solar, and other forms of renewable generation began to grow significantly, planners were faced with the question of how these weather-dependent resources should be counted toward total system need. Many incorporated simple heuristics into the traditional PRM accounting framework to derate the contributions of renewable resources relative to their nameplate capacity based on some measure of their expected output during peak periods. These heuristics implicitly presumed that a continued focus on the peak was needed to ensure resource adequacy.[5]

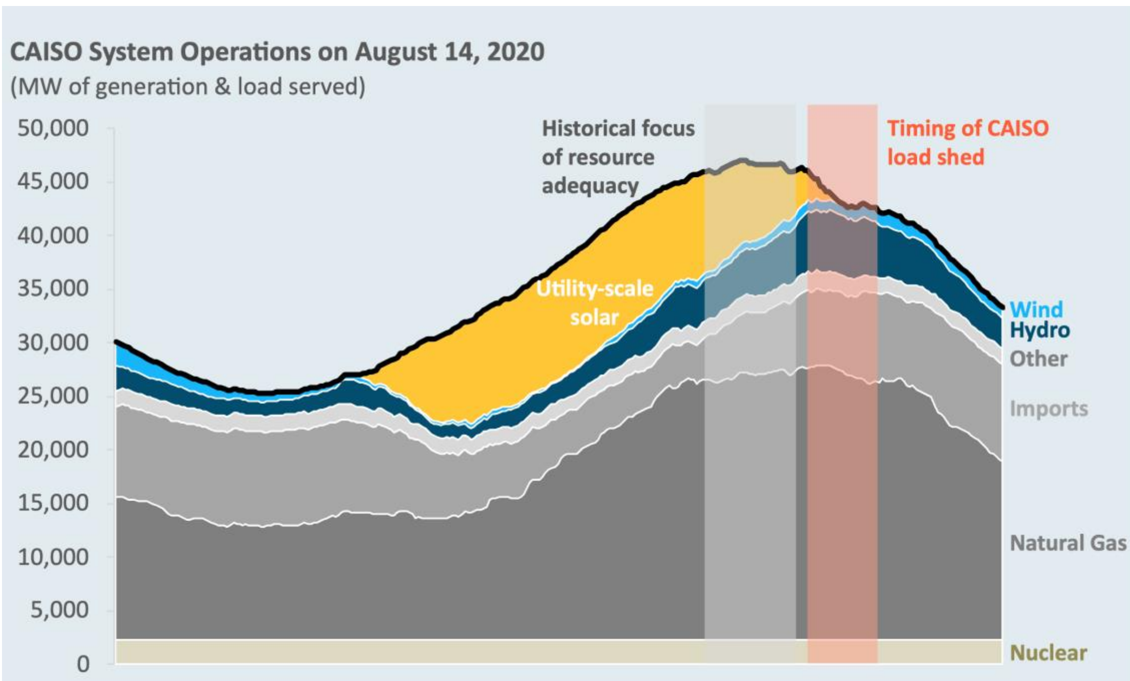


Figure 3: *California's rotating blackouts on August 13-14 of 2020 occurred not during peak demand hours, but after sundown when solar generation fell to zero*

However, as penetrations of wind and solar resources grew, so did a recognition that the variability of wind and solar generation would eventually cause the periods of risk to shift away from the traditional peak period and into periods with low renewable energy production.[6] A clear example of this phenomenon occurred in August 2020 (illustrated in Figure 3), when the California Independent System Operator ("CAISO") experienced rotating outages due to insufficient supply. Notably, the

[5] California Public Utilities Commission. *Adopted Qualifying Capacity (QC) Counting Methodology Manual*, Section 4.1. https://www.cpuc.ca.gov/-/media/cpuc-website/files/legacyfiles/a/9187-adopted-qc-methodologymanual.doc.

[6] Energy Systems Integration Group. *New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements*. Reston, VA: ESIG, 2024. https://www.esig.energy/new-resource-adequacy-criteria/.

outages did not occur during the afternoon peak load hours, but rather after sundown when load was significantly lower and solar output was near zero.

This event, and subsequent "near-misses" on September 6, 2022 and September 5, 2024, demonstrate a fundament shift in the critical period in California – the period in which California is most likely to experience loss-of-load no longer occurs when load is highest, but rather after sundown and later in the season when load is lower but California's capability to produce electricity is diminished. This period is often described as the "net peak", the time when load minus variable generation is highest. This shift has profound implications for how California and other regions should plan their portfolios of demand-side and supply-side resources. The most obvious is that additional solar generation does little to help avoid loss-of-load events that occur after sundown. It is also readily apparent that load reduction programs are most helpful during the evening period; indeed, California's "Power Down" program now encourages consumers to save electricity between 4:00pm and 9:00pm.[7]

2.2.2 Saturation, Diversity, and Interactive Effects

More generally, the California outage event illustrates the **saturation effect** relative to resource capacity contribution – the reduction in the effectiveness of a given resource in avoiding loss-of-load as its penetration grows. The declining marginal effectiveness of solar is already a key consideration for resource planners and investors in California and other jurisdictions with high solar penetration. This effect is illustrated in the top panel in Figure 4, which shows the diminishing effectiveness of successive tranches of solar at reducing net load (total electricity demand minus variable renewable generation).

While energy storage is a small contributor to resource adequacy today, modeling indicates that it too will be subject to diminishing returns as penetrations increase to 20% or more of peak demand.[8] By charging during low-load hours and discharging during high-load hours, energy storage has the practical effect of "flattening" the net load curve across time. However, increasing storage durations are required as more storage capacity is added to continue to provide additional flattening. The diminishing marginal effectiveness of energy storage is illustrated in the bottom panel in Figure 4 below.

[7] Energy Upgrade California. *Time-of-Use*. Accessed May 12, 2025. https://energyupgradeca.org/time-of-use.

[8] California Public Utilities Commission. *Summary of Updated SERVM and RESOLVE Analysis*. Presentation, January 12, 2024. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/2024-01-12-presentation-summarizing-updated-servm-and-resolve-analysis.pdf.

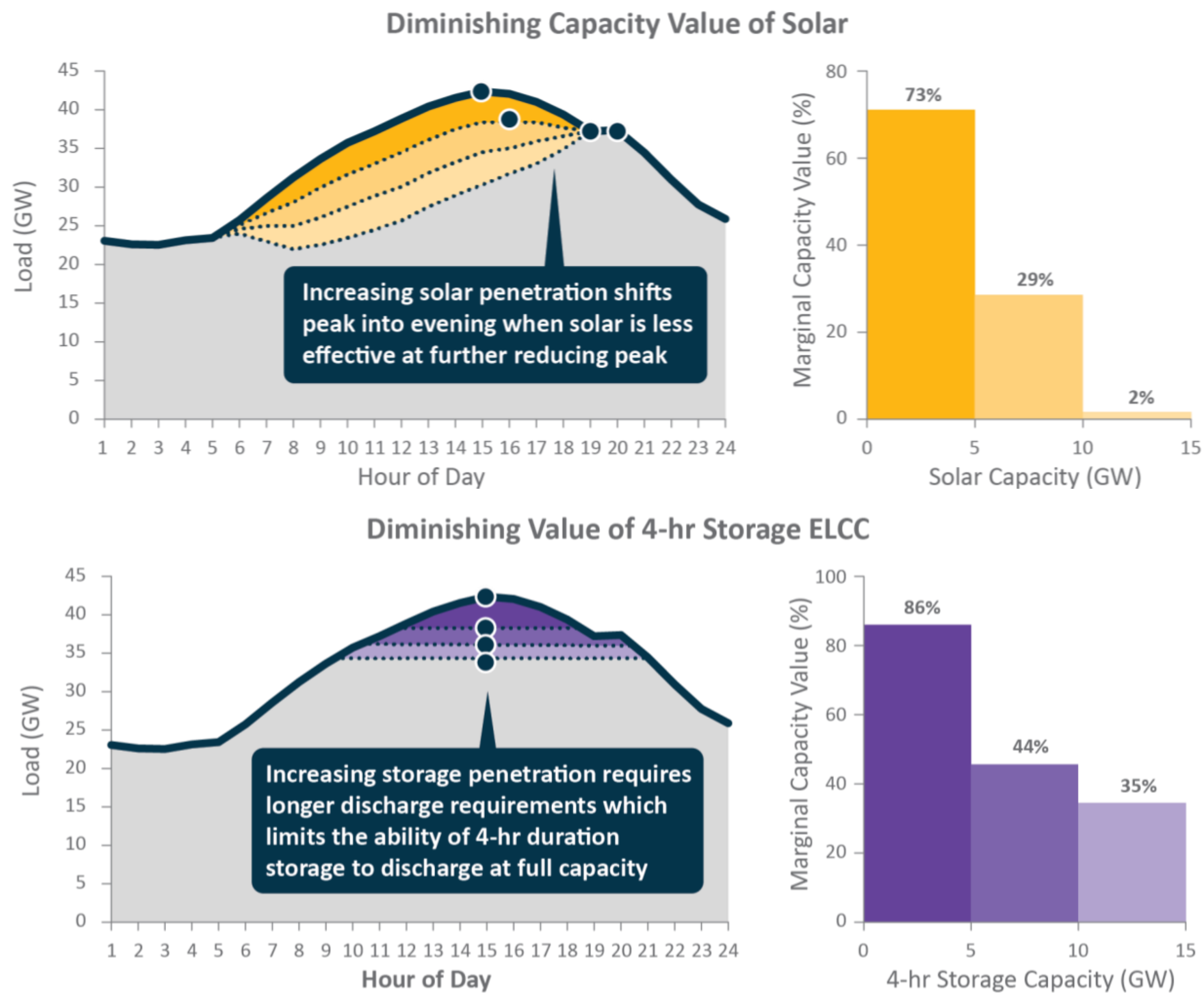


Figure 4: *Solar and storage resources exhibit diminishing marginal contributions to reliability as penetration increases*

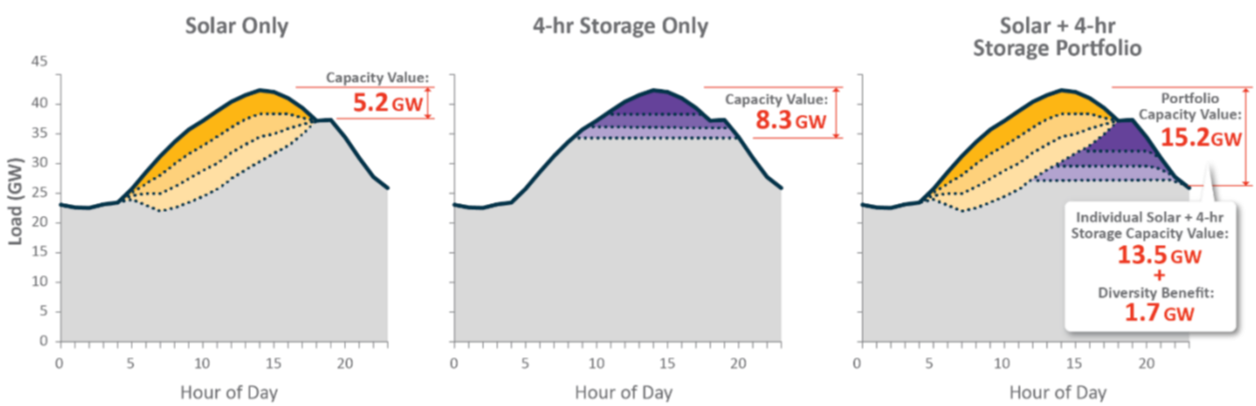


Figure 5: *The combination of solar and storage provides greater reliability benefits than either resource alone, partially mitigating each resource's saturation effect*

The saturation effect for individual resource types can be mitigated to a degree through the addition of complementary resources. Solar and storage provide an instructive example to illustrate this phenomenon: a combination of solar and four-hour storage resources provides more value to the system than the sum of the two independently. This is often described as a "**diversity benefit**," resulting from the fact that four-hour storage provides more incremental value to a system with higher solar penetration, because the solar shifts critical periods into a narrower window better suited to short-duration storage dispatch.[9] Other examples of complementary resources include solar and wind (due to complementarity of output profiles), wind and longer duration storage (due to longer cycling times between high and low output for wind resources), and either wind or solar plus hydroelectric resources with reservoir storage.

While some resource combinations mitigate saturation effects, other combinations may *exacerbate* saturation effects, because the resources have operational characteristics that are similar. Energy storage, hydropower with reservoir storage, and flexible loads all serve the function of flattening the net load curve. Each of these resources has limitations in its ability to provide energy during critical periods, whether physical or contractual. The more similar these limitations are, the more these resources compete with each other for a limited quantity of capacity value. For example, battery storage, hydropower with diurnal shaping flexibility, and demand response with a single, multiple-hour call per day have similar ability to provide energy or reduce load during a critical period that occurs on a single day (e.g., in the evening hours), and the presence of one or more of these resources diminishes the value of the others.

Saturation, diversity, and resource competition are all examples of **interactive effects** among resources in a portfolio. All resources interact with each other to a degree, but some are more interactive than others. Because solar electricity generation is concentrated during a relatively small number of hours of the year, interactive effects among solar resources lead to a rapid decline in marginal effectiveness. However, its predictable diurnal production pattern pairs well with limited-duration battery storage, causing a strong positive interactive effect. Battery storage also benefits from an interactive effect with firm generation, as batteries today are generally charged with output from thermal electric generators during stress conditions. These interactive effects are the primary driver of the need to shift to a critical periods reliability framework.

Incorporating these dynamics has required planners to carefully consider how to count variable and energy-limited resources towards resource adequacy needs. Because conventional thermal resources were generally alike in their reliability contributions, historical accounting conventions often did not differentiate among them; the commonly used ICAP approach for measuring need counts all firm resources at their nameplate values and incorporates the effects of potential forced outages into the reserve margin calculation. The Unforced Capacity ("UCAP") approach improves on ICAP by calculating resource-specific capacity credits that are derated by expected forced outage rates and lowers the PRM requirement accordingly. However, neither approach is sufficient for wind and solar generation, where periods of resource unavailability are not based on random forced

[9] Note that it is just as valid to describe the diversity benefit as solar providing more incremental value on a system with higher storage penetration, as it allows the storage to operate more efficiently to meet the remaining needs of the grid.

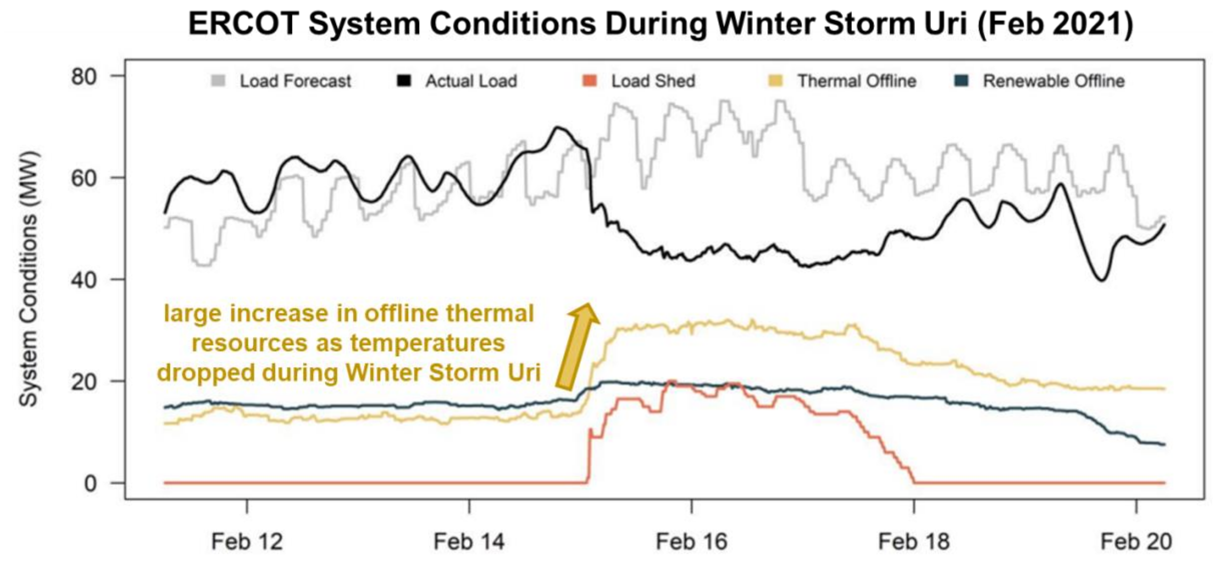
outages but rather are the product of systematic conditions related to weather and planetary motion. Indeed, alternative metrics such as "sustained peaking capability" were already used for resources such as hydropower, where nameplate capacity was not a good proxy for its actual contribution.

To remedy these shortfalls and accurately measure the contribution of variable and energy-limited resources as penetration grows, analysts are increasingly turning to **effective load carrying capability** ("ELCC") as the primary metric of capacity contribution. ELCC is a natural extension of LOLP modeling, measuring the change in total capacity provided by a portfolio of resources from adding or subtracting a quantity of an individual resource type. ELCC measures the capacity contribution from adding resources individually or in combination, providing a means to send efficient signals for investment in each resource type based on the marginal contributions it makes toward the portfolio's ability to avoid loss of load.

2.2.3 Conventional Resource Performance

While much of the focus in recent years has been on the appropriate accreditation of variable energy resources, recent events have also exposed vulnerabilities in traditional practices that were previously not well understood for the treatment of conventional resources. During extreme winter storms, challenges related to fuel supply and correlated high outage rates of firm resources have been proximate causes of rotating blackouts in Texas and across the Southeast. The potential for significant quantities of firm generators to fail at the same time is not fundamentally dissimilar from a large quantity of wind or solar going offline due to widespread reduced wind conditions, cloud cover, or sundown. Many independent System Operators ("ISOs") who currently use ELCC methods to accredit renewables are beginning to extend these concepts to thermal resources as well.[10]

[10] [9] PJM Interconnection. *2025/2026 Base Residual Auction ELCC Class Ratings*. https://www.pjm.com/-/media/planning/res-adeq/elcc/2025-26-bra-elcc-class-ratings.ashx.



Source: UT Austin Energy Institute, *Timeline and Events of the February 2021 Texas Electric Grid Blackouts*

Figure 6: *Significant outages of natural gas generation were a key contributor to the rotating outages on the ERCOT system during Winter Storm Uri*

As grid conditions continue to evolve, it will be vital for the industry's reliability constructs to continue to provide appropriate signals about the needed capabilities. Many studies that have examined long-term reliability risks have concluded that the increasingly heterogeneous mix of resources (thermal, renewables, storage, demand-side) alongside evolving system loads (due to electrification, data centers, etc.) will cause reliability risks not only to shift between hours of the day but also from one season to another. Even in a summer-peaking electricity system, very high penetrations of renewables and storage may eventually shift risk to the winter when periods of sustained low renewable generation availability, lasting days to weeks, are more common. Figure 7 below from California demonstrates how even a southwestern region with a strong summer peak and mild winter weather is expected to become winter-constrained by 2040 due to high penetration of solar energy and electrification of building heat.[11] It is critical for both utility planners and wholesale electricity market operators to appropriately capture and incorporate these risks into the capacity planning and procurement frameworks.

[11] Energy and Environmental Economics (E3). *Long-Run Resource Adequacy under Deep Decarbonization Pathways for California*. June 2019. https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf.

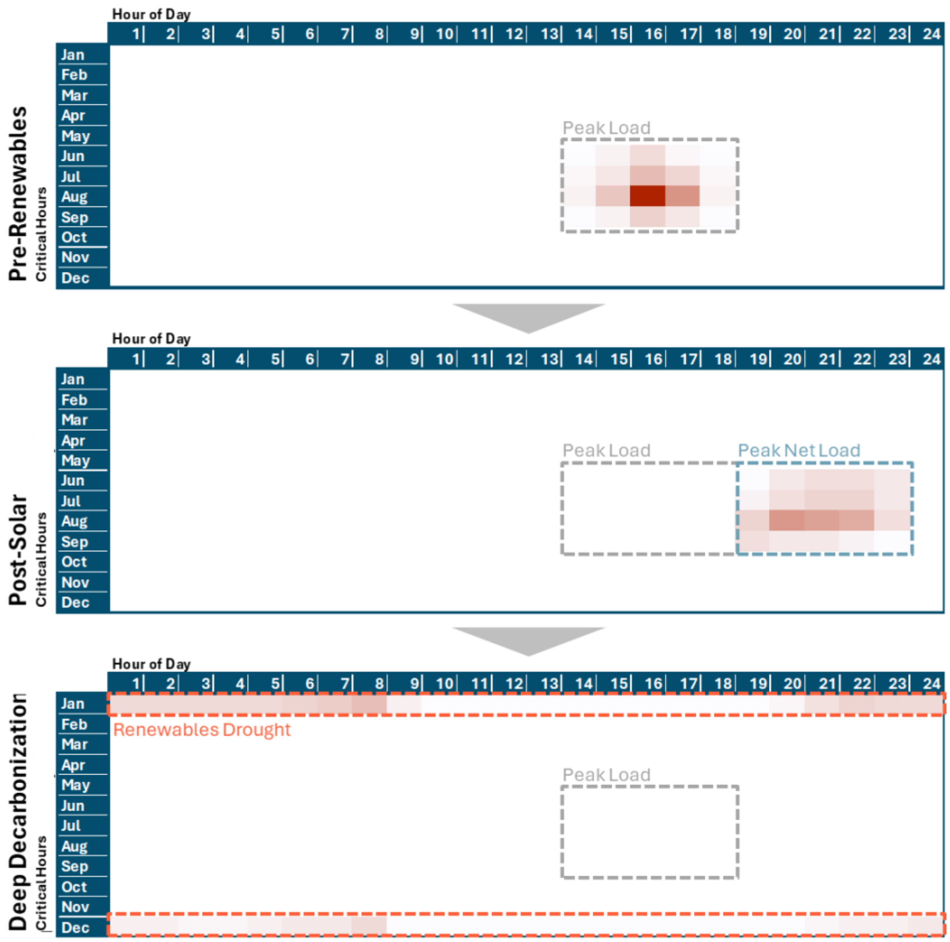


Figure 7: *Critical reliability periods are projected to shift to wintertime over the next 20 years due to high solar penetrations and building electrification, even in regions like California with mild winter weather*

3 A Critical Periods Reliability Framework

Ensuring resource adequacy for a future electric system under higher penetrations of variable energy resources hinges on the ability to design the system to perform under the most constrained conditions – whenever they may occur. These are **"critical periods"**: periods when the electricity system has reached or exceeded its maximum limits to serve electricity demand, meaning that loss of load has already occurred, is occurring, or is imminent. From this definition, it naturally follows that during critical periods, any additional generation or load reduction would improve system reliability. As discussed in the previous section, designing the system to perform during these critical periods has always been the primary challenge of resource adequacy. Historically, those critical periods coincided almost exclusively with peak load, but in the future, critical periods will increasingly occur at different times of day and year due to combinations of high load and low resource availability.

3.1 Need for a Reliability Framework

This paper lays out the theoretical and practical considerations of a critical periods reliability framework. It does not directly address the question of whether a reliability framework *is needed at all*. Some have argued that reliability frameworks are not needed,[12] and that economic efficiency is advanced when spot energy and ancillary service markets are allowed to clear at prices that are high enough to induce investment. While there are theoretical merits to these arguments, we observe that there are a number of practical barriers to achieving an economically optimal level of reliability using spot energy markets alone:

+ Most energy markets have price caps that prevent the market from clearing at consumers' value of lost load during critical hours.
+ Automated bid mitigation in energy markets, meant to prevent the exercise of market power, may also prevent the market from reflecting scarcity premiums that may be needed to induce investment.
+ Many electricity consumers are shielded from the impact of volatile hourly wholesale electricity prices through regulated retail rates that are not time-varying, preventing them from responding optimally to scarcity conditions.
+ Many electricity consumers lack the wherewithal to track and respond optimally to volatile wholesale electricity prices, even if they could benefit from doing so.
+ Market operators lack the ability to target individual consumers for reduced energy delivery based on their individual preferences; instead, power is rationed during scarcity events through random, rotating outages. This creates a reliability "externality" that prevents

[12] Riesz, J., & Milligan, M. (2013). *Examining the Viability of Energy-Only Markets with High Renewable Penetration*. CEEM, University of New South Wales. Chattopadhyay, D., & Alpcan, T. (2015). *Capacity and Energy-Only Markets under High Renewable Penetration*. Academia.edu. Hohl, C., & Lo Prete, C. (2024). *Capacity Markets vs. "Energy Only" Markets with Improved Scarcity Pricing Under Increasing Wind Penetration*. SSRN.

individual consumers from selecting their desired level of reliability and exposes all consumers to reliability risk due to the actions of others.

For these reasons, this paper starts from the premise that a resource adequacy construct is needed. Nevertheless, it is important to note that both the Electric Reliability Council of Texas ("ERCOT") and the Alberta Electricity System Operator ("AESO") markets operate without formal forward capacity mechanisms; ERCOT's market design does include administrative scarcity pricing mechanisms in spot energy and ancillary service markets intended to generate premiums to help enable resources to recover their investment costs. We also note that the more the barriers above can be addressed, allowing true scarcity to be reflected in spot energy and ancillary service markets, the less consequential the additional revenue available through a residual capacity market would be for market participants.[13]

3.2 Formalizing an Updated Conceptual Framework

3.2.1 Mathematical Formulation

The anticipated impacts of increasing reliance on variable and energy-limited resources and the improved understanding of risks attendant to firm resources underpin the need for improvements in processes used for need determination, need allocation, and capacity accreditation in both electricity system planning and organized wholesale electricity markets to maintain resource adequacy.

As previously discussed, the changes that are needed are an update and generalization of the traditional capacity planning framework. The traditional ICAP framework of planning for peak load and accrediting resources based on their nameplate capacity is based on a simplification of a more general problem. Specifically, the ICAP framework makes three simplifying assumptions:

(1) It assumes that the critical periods when loss-of-load risk is highest occur during peak load conditions.
(2) It assumes that there are only small differences in resource performance during the critical periods.
(3) It assumes that all resources are independent, i.e., that the presence of one resource does not affect the ability of another resource to perform during the critical period.

Under these simplifying assumptions, the total resource need can be defined as the expected peak load plus a PRM, and the individual resource accreditations can be aggregated using a simple summation:

[13] Under equilibrium conditions, economic theory holds that capacity markets would clear at the net cost of new entry ("net CONE"). If the revenue available through spot energy and ancillary services markets were sufficient to induce new generation investment on their own, the net CONE would be zero and the forward capacity market would clear at zero.

$$Total\ Need = Median\ Peak\ Load * (1 + ICAP\ PRM\%)$$
$$Capacity\ Available = \sum_{i}^{n} G_i$$
$$where\ G_i = Nameplate\ capacity\ of\ generator\ i$$

This system is calibrated to a loss-of-load standard by changing the PRM; the PRM is the quantity of resources needed in reserve to meet the standard. Because resources are accredited based on their nameplate value, the more that actual resource performance deviates from nameplate, the higher the PRM must be.

These simplifying assumptions were never strictly valid even for conventional systems. Thermal generators can differ from each other in their ability to perform at peak, and other methods were needed for resources such as hydropower that are constrained in their ability to perform during the peak period. These simplifications are increasingly inaccurate as variable and energy-limited resources make up a larger share of total system capacity:

(1) The critical periods are no longer the same as the peak load periods, requiring a shift away from a simplistic focus on peak load periods for capacity planning.
(2) There are large differences in resource performance during critical hours, requiring more precise ways of measuring individual resource contributions.
(3) Resource contributions are not independent, i.e., there are significant interactive effects from adding resources of different types, which yield changing resource contributions as the loads and resources evolve. This requires a shift away from a simple linear summation of resource contributions toward a more complex, non-linear function.

The more general formulation of the problem is as follows (a more detailed mathematical formulation is provided in the appendix):

$$Total\ Need = Capacity\ \ needed\ to\ meet\ reliability\ standard\ (MW)$$

$$Capacity\ Available = \ Portfolio\ ELCC\ = \ f(G_1, G_2, \ldots, \ G_n)\ (MW)$$

$$where\ G_i = Nameplate\ capacity\ of\ generator\ i$$

$$Marginal\ ELCC_{G_i} = \frac{\partial f}{\partial G_i}(G_1, G_2, G_3, \ \ldots\ G_n)\ (\%)$$

The total capacity provided by a given fleet of resources, its **Portfolio ELCC**, is represented as the equivalent perfect capacity that could be replaced through a portfolio of real-world resources while maintaining reliability. Portfolio ELCC is a multi-dimensional function of the portfolio of resources being measured, with each dimension representing increasing quantities of an individual resource type. The Portfolio ELCC function is concave and monotonically increasing along each dimension, meaning that continued additions of a given resource type yield an increase, or at worst no change, in Portfolio ELCC. This is illustrated in the left-hand panel in Figure 8.

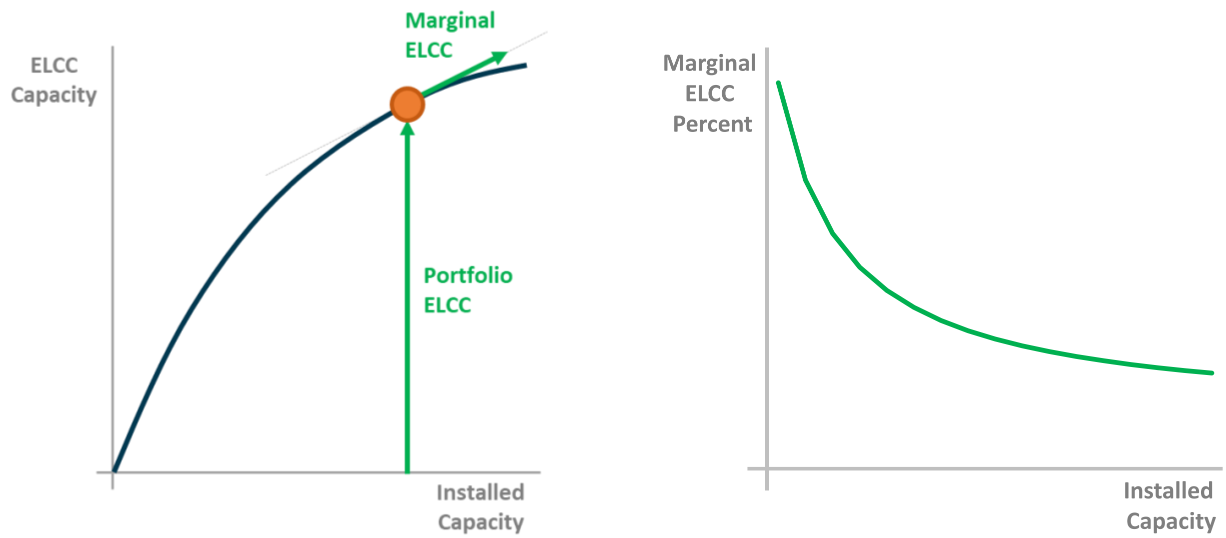


Figure 8: *Portfolio ELCC is described by a multi-dimensional function or "surface". Marginal ELCCs are described by the gradient of the surface along each dimension. Marginal ELCC declines as a function of resource penetration*

The **Marginal ELCC** of a specific resource is the change in Portfolio ELCC due to a change in the quantity of the resource; mathematically, it is the partial derivative of the Portfolio ELCC function with respect to the change in the specific resource quantity. The Marginal ELCC curve for any given resource type is convex and monotonically decreasing, meaning that continued additions of a given resource will at best yield a linear increase in Portfolio ELCC and in many cases will exhibit diminishing marginal returns. This is illustrated in the right-hand panel in Figure 8.

The shape of the Marginal ELCC curve for an individual resource type depends on the extent to which continued additions change the critical hours. Solar has a high initial capacity contribution in summer-peaking systems; however, daylight hours are quickly saturated, and its marginal capacity contribution diminishes rapidly as the critical hours shift into the evening. Wind generation occurs more sporadically throughout the year; its Marginal ELCC therefore starts at a lower level and declines more slowly. Firm resources tend not to change the critical hours and are therefore less subject to diminishing returns, although there may be exceptions in cases where correlated risks are present, for example when a large resource is added to a small system, or when a gas pipeline constraint limits the aggregate availability of fuel during wintertime cold weather events.

Due to interactive effects, the Marginal ELCC of an individual resource is also a function of the penetration of **all resources**. For example, the Marginal ELCC of a storage resource will generally be higher in the presence of large quantities of solar and vice-versa, as described above. When making investment decisions, system planners and market participants must anticipate how changes to the portfolio over time will change the accreditation of each individual resource.

This conceptual framework also breaks the link between the sum of individual resource accreditations and the total quantity of capacity provided by a portfolio. Because of saturation, the sum of individual Marginal ELCCs is lower than the Portfolio ELCC; indeed, the more the Marginal ELCC of an individual resource type declines, the larger this gap will grow. This necessitates an evolution away from an "accounting" framework where resources are listed in a table in which their individual accredited values sum to the Portfolio ELCC. The presence of interactive effects means that some capacity is provided by the entire portfolio and is not uniquely attributable to any individual resource.

3.2.2 Four Elements of the Critical Periods Framework

The critical periods reliability framework outlined above retains all aspects of resource adequacy planning and market mechanisms but reorients them to focus upon critical periods rather than solely upon the traditional peak period. By focusing on the periods that are critical to reliability, this framework provides market signals for entry, exit, and load participation that reflect their marginal value.

Application of the framework relies on four key elements:

1. **Total Reliability Need** is the total quantity of perfect capacity needed to achieve the desired resource adequacy standard, meeting load plus minimum operating reserves requirements during all hours of the year. For an electricity system at target reliability, the Portfolio ELCC of all resources will exactly equal the Total Reliability Need.
2. **Capacity Accreditation** for each resource is determined based on its marginal contribution to Portfolio ELCC, i.e., its Marginal ELCC, which can also be understood as representing its expected performance during critical periods.
3. **Total Procurement Need** is the quantity of accredited capacity from the actual available resources, accredited at their Marginal ELCC values, that must be procured to meet the reliability standard. This is calculated as the sum of accredited capacity from individual resources, for a system that is tuned as needed to meet the reliability standard through addition or subtraction of perfect capacity. This is equivalent to the system requirements (load plus operating reserves) during critical periods.
4. **Allocation of Procurement Need** is based on each load-serving entity's load during critical periods.

We describe the application of each of these elements in both the central planning and market contexts in the next section.

3.3 Practical Application of the Critical Periods Framework

The generalized mathematical formulation described above is broadly applicable to any electricity system, regardless of loads, resource mix, reliability standard, or other differentiating factors. How these mathematical relationships are applied depends on whether the framework for ensuring resource adequacy relies on the procurement actions of a single entity (as in a vertically integrated utility) or multiple entities within a larger system (as in a capacity market or resource adequacy program):

- A **central planner** is responsible for maintaining a portfolio of resources to meet a desired standard for adequacy. Strictly speaking, this does not require assignment of value to individual resources, but it does require a representation of the full **Portfolio ELCC function** and the corresponding **Total Reliability Need** to support informed long-term investment decisions. By procuring a portfolio of resources whose total value is equal to the Total Reliability Need, a central planner will implicitly be making procurement decisions "on the margin," as the change in the Portfolio ELCC function with each decision captures how the addition (or removal) of capacity affects the total portfolio. Simplifications of this approach are already common practice among utilities today, many of which rely on combinations of the UCAP approximation, ELCC curves, and multi-dimensional ELCC surfaces as a means of representing the full Portfolio ELCC function in a mathematically tractable manner. This application is discussed further in Section 3.3.1.
- In a **market environment** (either a capacity market or resource adequacy sharing program), the assignment of value to individual resources is fundamental to providing efficient signals for new investment and requires an approach that creates a fungible, non-discriminatory reliability product. This necessarily requires that *all resources* be accredited based on their marginal contribution to system needs – their **Marginal ELCC**. The total quantity of accredited capacity that must be procured to meet the target reliability standard is the Total Procurement Need. Because the sum of Marginal ELCCs is always lower than the Portfolio ELCC, the quantity of accredited capacity procured is always less than the Total Reliability Need. The mathematical properties of the Portfolio ELCC function ensure that this quantity is sufficient to meet load even during the highest peak load hours. The difference between the Total Reliability Need and the Total Procurement Need can be understood to represent the inframarginal capacity value of a portfolio of resources, and the difference in load and operating reserve requirements between peak periods and critical periods. This application is discussed further in Section 3.3.2.

Despite their difference in focus, these two applications (illustrated in Figure 9) are directly related to one another by the underlying mathematical fundamentals described in Section 3.2.1 and should be understood as complementary representations of the same problem.

Indeed, despite their different focuses, in both cases, a rigorous understanding of all aspects of the mathematical fundamentals is needed. Quantifying the Marginal ELCC of different resources will ultimately be necessary for vertically integrated utilities to justify procurement decisions, to determine appropriate terms and pricing for bilateral contracts and qualifying facilities, and to derive avoided costs for valuation of demand-side resources. In a market environment, an understanding of the Portfolio ELCC function will be necessary for market participants to make informed investment decisions based on long-term fundamentals and to inform long-term resource outlooks necessary for complementary planning functions (e.g. long-term transmission planning).

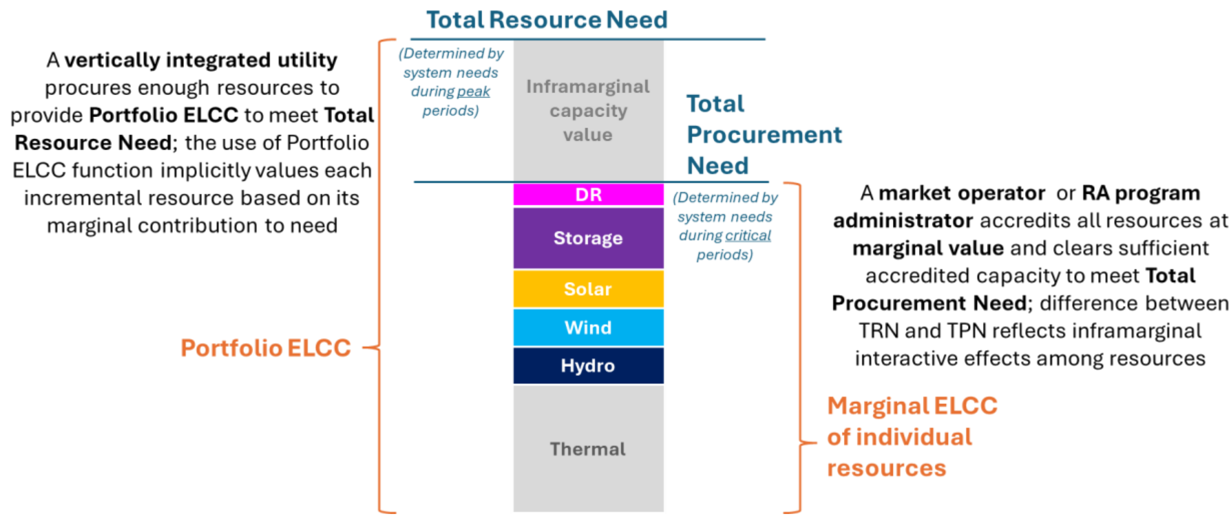


Figure 9: *Two complementary applications of the Critical Periods Reliability Framework*

3.3.1 Critical Periods Framework in Optimal System Planning

Outside the context of competitive electricity markets, ELCC concepts have gained widespread use among vertically integrated utilities that plan their own systems in a least-cost manner, subject to constraints around environmental and reliability objectives. This section describes the application of the critical periods framework for optimal system planning.

Total Reliability Need Determination

The first step in implementing the critical periods reliability framework is to calibrate an LOLP model by adding perfect capacity until the reliability standard is exactly satisfied, i.e., meeting load and operating reserve requirements subject to an acceptable level of loss-of-load. The total amount of perfect capacity (a hypothetical resource that is always available to generate energy) required in this step to meet the standard is the Total Reliability Need.

The Total Reliability Need is independent of the resource portfolio and is calculated using only perfect capacity. A system's perfect capacity need is determined by the characteristics of the electric load the system must serve, specifically the inter-annual variability in peak loads, along with the quantity of any operating reserves that must be carried even during system emergencies to avoid the potential to cause cascading outages. A perfect capacity planning reserve margin ("PCAP PRM") is calculated as the Total Reliability Need divided by the median or "1-in-2" peak load, minus one. The PCAP PRM provides a ready means to adjust the need over time as load changes. It is also used to constrain optimal portfolio modeling to ensure that future portfolios will meet resource adequacy needs.

A calibrated model that reflects the actual portfolio is needed for system analytics such as resource accreditation. To the extent that this portfolio does not exactly meet the reliability standard, perfect capacity is added or subtracted (i.e., negative generation) through a calibration process until the system is exactly at target reliability. The sum of the Portfolio ELCC of actual resources and any additional perfect capacity is by definition equal to the Total Reliability Need; the actual physical system exactly meets the resource adequacy standard when the quantity of perfect capacity is zero.

Resource Accreditation

LOLP modeling is then used to map out a piecewise-linear or planar approximation of the Portfolio ELCC surface that represents the perfect capacity displaced from the Total Reliability Need as real resources are added. This surface represents how the Portfolio ELCC of non-perfect capacity and the Marginal ELCCs of these resources change as the quantity of each resource changes.[14] As discussed above, Portfolio ELCC represents the aggregate capacity provided by a collection of resources, including interactive effects. Marginal ELCC represents the incremental contribution to the Portfolio ELCC of a particular resource and is consistent with the accreditation that a resource would receive in the critical periods reliability framework.

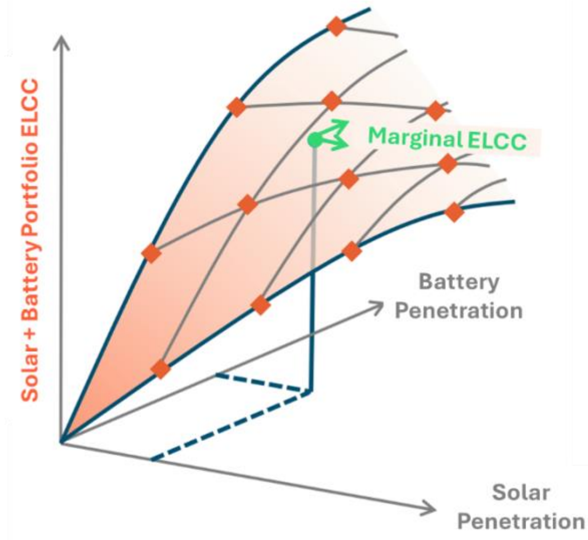


Figure 10: *Example of a two-dimensional ELCC surface for use in optimal capacity expansion modeling*

A piecewise-planar approximation of the Portfolio ELCC surface enables an accurate representation of capacity needs as a function of the resource portfolio in long-term capacity expansion modeling, with each dimension of the surface capturing the marginal contribution of an individual resource type and the portfolio effects capturing changes in saturation and diversity effects across all different combinations of resources. In practice, computational limitations may require planners to be selective about which portions of the surface to map with precision. Planners will need to make informed judgments about the number of dimensions to consider and the granularity of resource additions along each dimension, balancing accuracy against practical considerations. Methods have also been proposed for endogenizing the calculation of ELCC values across a surface.[15] Because computational limitations require the use of imperfect approximations of the ELCC surface, one or a handful of resulting portfolios should be tested against resource adequacy standards using a full LOLP model run before final procurement actions are taken.

This framework allows utilities to evaluate resource procurement decisions based on their marginal impact to system reliability, i.e., their performance during the critical periods. This is accomplished by first calculating the Total Reliability Need for a test year and translating that into a PCAP PRM that adjusts the total need as load changes over time. This is incorporated into a system adequacy

[14] Many utilities have adopted such an approach in portfolio planning including NV Energy, Puget Sound Energy, Xcel, Public Service Company of New Mexico, and Arizona Public Service

[15] GridLab. *Iterative Portfolio Optimization: A Framework for Resource Planning in the Clean Energy Transition*. https://gridlab.org/portfolio-item/iterative-portfolio-optimization/.

constraint in the optimal capacity expansion modeling framework that requires all portfolios to have a Portfolio ELCC greater than or equal to the Total Reliability Need. ELCC surfaces used in system planning and procurement trace out the changing Portfolio ELCC and Marginal ELCCs of individual resources as the portfolio evolves, accounting for portfolio effects that represent the shifting critical hours. The derivation of a piecewise-linear ELCC curve is shown in Figure 11.

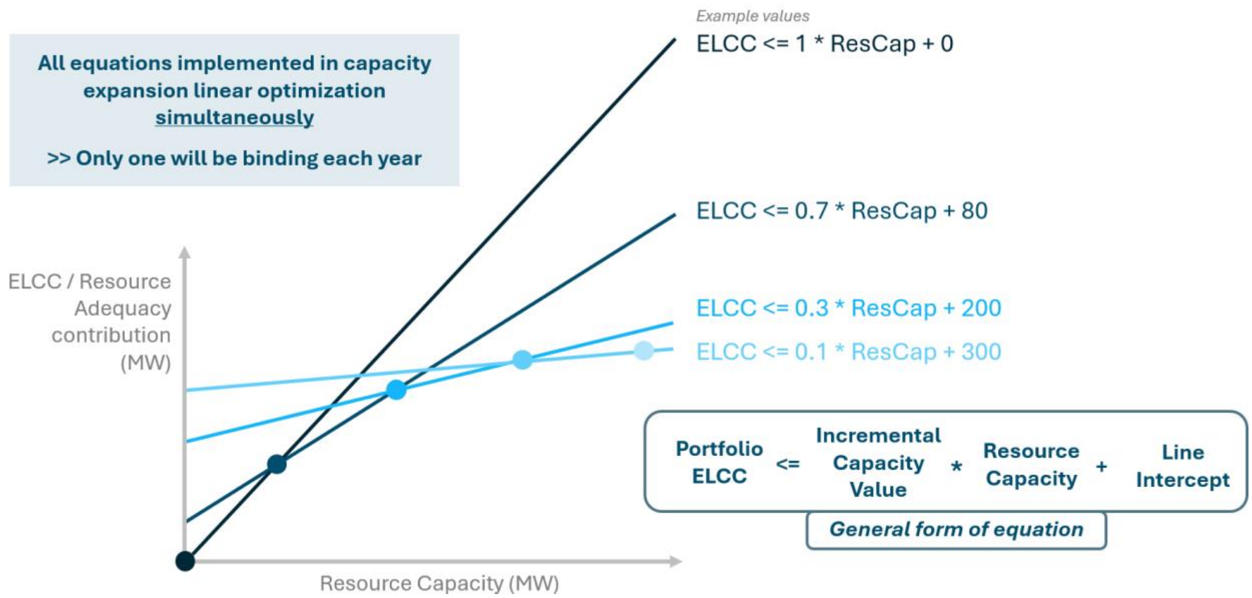


Figure 11: *The derivation of a piecewise-linear ELCC curve used to constrain the solution of an optimal long-term capacity expansion model*

Importantly, within an optimization framework, these decisions are not based just on the Marginal ELCC at the time of resource procurement but rather on changes to the marginal value the resource provides over its lifetime as other resources are added that impact its Marginal ELCC. This is consistent with the signals that a project developer would face in a competitive electricity market in forecasting Marginal ELCC values (and corresponding capacity market revenues) over the lifetime of a potential project.

The critical periods framework also ensures a level playing field between resources with different operating characteristics. Traditionally, utilities have used an ICAP or UCAP approach to accredit thermal resources, while most are moving to ELCC for renewable and energy storage resources. The use of disparate methods across resource types creates the potential for distortions in utility procurement decisions. As indicated in Figure 12, the critical periods framework evaluates all resources consistently using a Marginal ELCC approach, including thermal resources, while incorporating both saturation and portfolio effects. This helps to ensure that the utility's procurement process will identify the least-cost resource additions and retirements that achieve its reliability target.

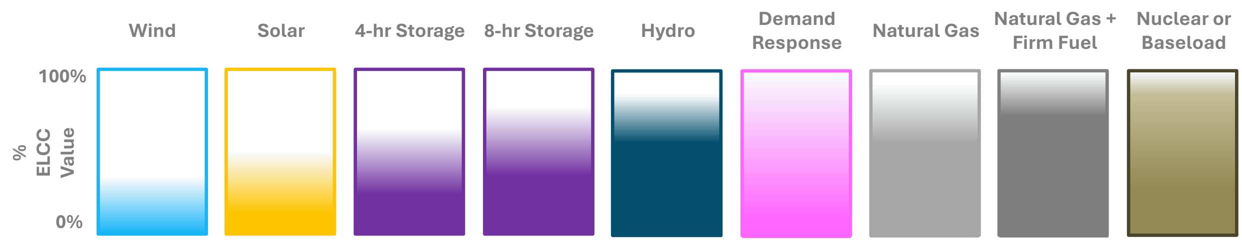


Figure 12: *The critical periods framework with Marginal ELCC accreditation creates a level playing field where all resources are valued based on their marginal contribution to system reliability*

Total Procurement Need Determination

This step is not strictly necessary in central planning, as the Portfolio ELCC function yields both the quantity of capacity needed to meet the Total Reliability Need (total function value) as well as the contributions of individual resources (Marginal ELCC gradients). However, central planners may still be faced with the challenge of how to account for the contributions of both existing and new resources within the context of the conventional, two-dimensional "loads and resources" table. Indeed, many vertically integrated utilities continue to utilize a traditional (i.e. peak-based) PRM for accounting purposes even while using Marginal ELCC for procurement decisions.

Some utilities have adopted methods for allocating Portfolio ELCC among all resources within the portfolio to continue to demonstrate compliance with a conventional, peak-based PRM, e.g., through the use of "average" ELCCs for all quantities of existing resources. However, this allocation is arbitrary and unnecessary and may cause confusion if the allocated values are inconsistent with the Marginal ELCC values used in portfolio development and resource procurement. A PCAP PRM with cumulative Marginal ELCC values, and a separate line item accounting for the interactive effects as illustrated in Figure 13, avoids this confusion, accurately identifying the marginal contribution of each resource and the combined contribution of the portfolio.

Allocation of Total Procurement Need

This step is likewise unnecessary in the central planning context where there is a single buyer of electricity supply resources. However, the principles and methods described below for need allocation in the market context may be useful for the regulatory purpose of cost allocation within a vertically-integrated utility, particularly in the case where some retail customers have the ability to procure all or a portion of their own power supply.

3.3.2 Critical Periods Reliability Framework in a Market Environment

While the mathematical concepts are the same for a market environment as for central planning, the application is somewhat different, and more exacting, because of the presence of multiple buyers and sellers. This section describes the application of the critical periods framework in the context of competitive markets.

Total Reliability Need Determination

Determination of the Total Reliability Need is the same in the market context as in the central planning context. First, an LOLP model is developed and the Total Reliability Need is calculated using perfect capacity only. Next, the perfect capacity is substituted with the actual portfolio for the specific system by removing perfect capacity while maintaining compliance with the reliability standard. Unlike in the central planning context, the Total Reliability Need is not used directly in market pricing, which, in accordance with economic principles, focuses on the marginal impacts for both loads and resources.

Resource Accreditation

The calibrated LOLP model is then used to determine the capacity accreditation of each resource based on its Marginal ELCC. It is important for the capacity accreditation method to provide economically efficient signals about the value of adding new resources or retiring existing ones by accrediting resources based on their marginal contribution to the total need. Accrediting a resource at a value that is higher than its Marginal ELCC would result in overinvestment in that resource and a more expensive power system than is needed to meet a given reliability standard, whereas too low an accreditation would result in underinvestment. A resource's Marginal ELCC is determined by its performance during critical periods, i.e., periods in which any additional resource results in an improvement in reliability (i.e. reduction in loss of load), and each resource's availability across those periods provides a direct measure of its relative marginal impact on reliability. Marginal ELCC is not impacted by resource availability outside of these periods.

Mathematically, the Marginal ELCC of a given resource type is the change in Portfolio ELCC with a small change in quantity of that resource type, or the partial derivative of the Portfolio ELCC function with respect to a single resource type. Stated differently, the Marginal ELCC is the quantity of perfect capacity that can be removed from the portfolio as a resource is added, while maintaining adherence to the reliability standard. Practically, it can be calculated in a number of ways including directly through repeated "in-out" runs of the LOLP model with small changes in the quantity of each resource type, indirectly through observation of the change in reliability (such as the marginal reliability improvement ("MRI") approach,[16] or the shadow price of an optimization), or through a vector product of resource availability and critical hours from an LOLP model run (the direct loss of load ("DLOL") approach).[17]

Multiple market operators are currently in the process of considering or implementing redesigns and new market mechanisms to focus on critical periods. These include:

- **New York Independent System Operator ("NYISO"):** Marginal reliability improvement[18]

---

[16] Potomac Economics. *Capacity Accreditation: Conceptual Framework*. Prepared for the New York Independent System Operator (NYISO), July 30, 2021. https://www.nyiso.com/documents/20142/23645207/20210730%20Potomac%20-%20Capacity%20Accreditation%20-%20Conceptual%20Framework-7-30-2021.pdf.

[17] Midcontinent Independent System Operator (MISO). *Resource Accreditation White Paper: Version 2.1*. 2024. https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf.

[18] Maloney, Peter. "FERC Rejects NYISO Buyer-Side Mitigation Provisions, Opening Door for More Clean Energy." *Utility Dive*, January 24, 2022. https://www.utilitydive.com/news/nyiso-buyer-side-mitigation-clean-energy-FERC/617848/.

- **PJM Interconnection ("PJM"):** Marginal effective load carrying capability[19]
- **Mid-Continent Independent System Operator ("MISO"):** Direct loss of load resource accreditation[20]
- **Independent System Operator – New England ("ISO-NE"):** Pursing a marginal reliability improvement approach but not yet implemented[21]

While these mechanisms are mechanically different – MISO's DLOL methodology calculates capacity credits by quantifying resource availability during periods of highest system risk, whereas NYISO calculates reduction in loss-of-load from adding individual resources – each focuses on the performance of the system and individual resources during critical periods: times when the system is at risk of experiencing loss-of-load. Thus, the market redesigns from NYISO, PJM, and MISO are all formulations of a Marginal ELCC or a critical periods reliability framework for need determination and resource accreditation.

[19] Behr, Peter. "FERC Approves PJM Capacity Accreditation Reform to Strengthen Grid Reliability." *Utility Dive*, March 27, 2024. https://www.utilitydive.com/news/ferc-pjm-capacity-accreditation-reforms-grid-reliability/706276/.

[20] Maloney, Peter. "FERC Approves MISO Capacity Accreditation Rules Tied to Resource Performance." *Utility Dive*, May 3, 2024. https://www.utilitydive.com/news/miso-midcontinent-ferc-capacity-accreditation-dlol/711716/.

[21] Walton, Robert. "ISO New England proposes 1-year delay to 2025 forward capacity auction." *Utility Dive*, November 7, 2023. https://www.utilitydive.com/news/iso-new-england-delay-FCA19-capacity-auction-accreditation/698973/.

Methods of Calculating Marginal ELCC Values

As with need determination, calculating resource accreditation can be performed in three ways. Each starts with an LOLP model calibrated to exactly meet the system reliability standard.

Method 1: Repeated LOLP model runs

The most straightforward approach to calculating Marginal ELCCs is by directly adding a small quantity of a specific resource type and then, through repeated model runs, calculating the quantity of perfect generation that can be removed from the system to return it to the original level of reliability. While this method is common, these calculations can be computationally intensive due to the multiple tuning steps required to determine how much firm capacity should be removed.

Method 2: Calculate Marginal Reliability Improvement using an LOLP model

To make the modeling tractable, some system operators have used MRI as a reasonable approximation to Marginal ELCC. This involves calculating ELCC as the ratio of (1) the change in reliability due to the addition of the resource of interest and (2) the changes in reliability from the addition of an equivalent amount of nameplate capacity of a perfect capacity resource.

Method 3: DLOL Approach: measure resource performance during modeled loss-of-load hours

This approach accredits resources by directly observing their availability during simulated critical hours. The DLOL approach uses a vector product of modeled hourly resource performance and critical hour, consisting of a value between 0 and 1 representing the criticality of the hour.

The accredited value of each resource will change over time based on future changes to conditions that lead to critical periods, as discussed above:

- If critical periods shift away from periods when a resource is available, its accredited capacity will decline.
- If critical periods shift towards periods when a given resource is available, its accredited capacity will increase. This may occur when the penetration of a complementary resource shifts risk into periods where the original resource is more available.

For electricity systems with growing portfolios of variable and energy-limited resources, critical periods are likely to move toward prolonged periods of low generation availability, particularly extended wind and solar droughts, meaning that the marginal reliability values of these resources will likely be lower than today. This decline is ameliorated to a degree by increasing adoption of energy storage, which can charge during periods of high resource availability and discharge during periods of low resource availability. Their energy-shifting capabilities tend to broaden the critical periods and potentially include some hours when variable generation is above its minimum levels. Long-duration energy storage would improve the accredited values of wind and solar generation through its ability to store surplus generation over longer periods. These dynamics will be captured organically by the evolving Total Procurement Need and Marginal ELCC resource accreditation under the critical periods framework.

This framework is equally suited to accreditation of thermal resources. Specifically, to the extent that thermal availability is lower during critical periods than during other periods, thermal resources receive accreditation that is lower than their average availability. Lower thermal availability is observed during critical periods for a number of reasons:

+ **Temperature-related reductions** in the maximum output of thermal generation capacity (available output of combustion turbines is lower under high temperatures).
+ **Correlated outages** among many thermal generators, as has been experienced during winter storms Uri and Elliott, in which widespread fuel availability and plant equipment issues caused a significant proportion of the thermal fleet to be unavailable during critical reliability periods.
+ **Size** – outages of very large generators (relative to the system size) are functionally equivalent to correlated outages of many smaller generators and can lead to a reduction in capacity accreditation for specific large generators.
+ **Tail events** – accreditation of thermal resources using a stochastic LOLP approach is likely to result in lower accredited values than a UCAP approach based on an individual resource's expected forced outage rate, even if all outages are uncorrelated. This is because loss-of-load events are statistically more likely to occur during periods of higher-than-expected thermal forced outages, even if thermal forced outages are random and uncorrelated.

The precise identification of critical periods is an important area of future research. While hours with loss-of-load can be observed directly in an LOLP model, a broader set of hours are relevant for systems with significant quantities of energy storage. For example, consider an LOLP simulation showing a day with unserved energy in the evening after energy storage resources are fully exhausted. On this day, any hour in which storage dispatch is needed to meet load is a critical hour, even if no loss of load is experienced during that hour. Additional hours may also be critical on this day if there is insufficient energy available to fully charge energy storage.

Total Procurement Need Determination

Within the critical periods reliability framework, the total quantity of effective capacity procured for a system that meets its resource adequacy standard is the sum of the accredited values of the individual resources. The Total Procurement Need is lower than the Total Reliability Need because saturation reduces the effectiveness of individual resources at meeting Total Reliability Need (mitigated to a degree by the procurement of complementary resources as described above). The gap between the Total Reliability Need and the Total Procurement Need is equal to the size of this interactive effect.

On a tuned system, i.e., a system that is calibrated to exactly meet its reliability standard such that Portfolio ELCC plus perfect capacity calibration = Total Reliability Need, this gap is also equal to the load difference between the peak periods and the critical periods. Thus, the Total Procurement Need can be determined directly by evaluating the load served and minimum operating reserves during critical periods. Ensuring sufficient resources are available during these periods – the most constrained periods of generation supply – will also ensure that loads can be served with an acceptable level of reliability across all other conditions experienced including the highest peak demand periods. [22] This follows from the derivation of the Total Procurement Need from a portfolio that is tuned to meet the Total Reliability Need. Intuitively, if the portfolio could not meet load during the peak hours, then the peak hours would themselves be critical hours.

The extent to which the Total Procurement Need decreases relative to Total Reliability Need is largely dependent on the penetration of variable and energy-limited resources. E3 research shows that the Total Procurement Need declines from approximately 110% of median peak load for a system with no renewables or storage to approximately 77% of median peak load for an ERCOT system with half of energy needs met by wind and solar.[23] PJM has indicated that the Total Procurement Need within their Marginal ELCC framework is equal to 94% of median peak load.[24] The difference between Total Reliability Need and Total Procurement Need is equivalently the difference in load during the peak hours and the load during the critical hours.

The following charts provide an illustration of the transition from a traditional, ICAP-based capacity framework to a critical periods framework that provides appropriate signals to all resources. The ICAP framework on the left in Figure 13 accredits all resources at their nameplate capacity, requiring a high planning reserve margin to make up for the fact that these resources are not always available.

Shifting to a critical periods framework on the right results in a lower Total Procurement Need because resource unavailability is appropriately accounted for in accreditation rather than "socialized" through a higher PRM. The Total Reliability Need thus accounts solely for load variability and operating reserves. The Total Procurement Need is the sum of individual resource accredited capacities, which is lower than the Total Reliability Need because of the saturation effects or, equivalently, the difference in load between the critical hours on a system with all perfect capacity – the peak load – and the critical hours on a system with high penetration of variable resources – effectively the net peak load.

---

[22] Energy Systems Integration Group. *Redefining Resource Adequacy for Modern Power Systems*. Reston, VA: ESIG, 2021. https://www.esig.energy/reports-briefs/redefining-resource-adequacy-for-modern-power-systems/.

[23] Energy and Environmental Economics (E3). *Assessment of Market Reform Options to Enhance Reliability of the ERCOT System*. Prepared for the Public Utility Commission of Texas, November 10, 2022. https://www.ethree.com/wp-content/uploads/2023/05/E3-PUCT_Assessment-of-Market-Reform-Options-to-Enhance-Reliability-of-the-ERCOT-System_11.10.22-Sent.pdf.

[24] PJM Interconnection. *IRM, FPR, and ELCC for 2025/2026 BRA – Presentation*. March 20, 2024. Slide 15. https://www.pjm.com/-/media/committees-groups/committees/mrc/2024/20240320/20240320-item-05---irm-fpr-and-elcc-for-25-26-bra---presentation.ashx.

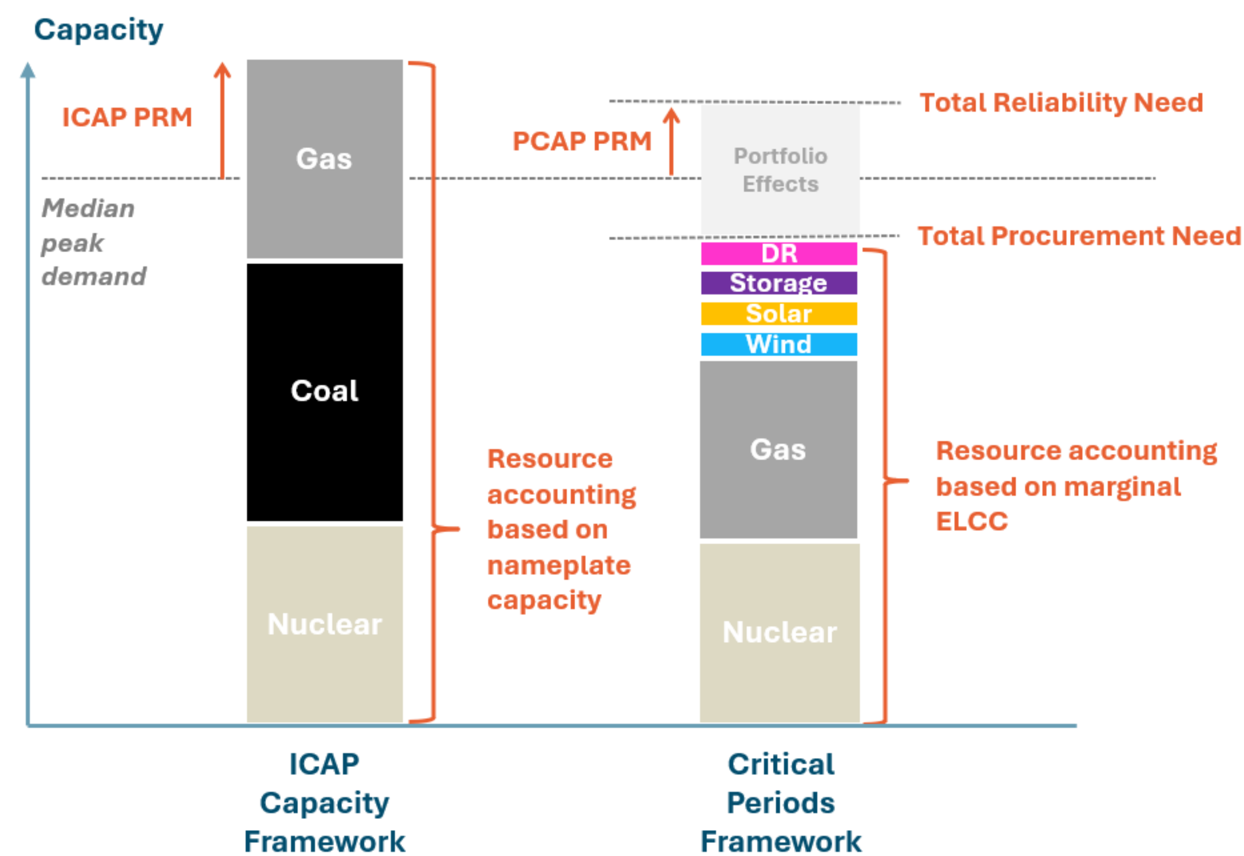


Figure 13: *Transitioning from an ICAP to a critical periods framework requires defining Total Procurement Need and accrediting resources based on their performance during critical hours*

Figure 14 below illustrates the equivalence of the saturation effects and the MW difference between the peak load and the critical hour load. If the system were composed of only thermal generation, the critical hours would be the peak load hours during the early afternoon. The presence of solar generation shifts the critical hours into the evening when the load is lower. This shift means that the quantity of capacity that must be procured is nominally smaller by the change in load between the peak hours and the net peak hours. This does not mean that less effective capacity is procured, however, because the change in load is equal to the interactive effect, which enables this nominally smaller quantity of procured capacity to continue to serve even the highest peak loads, likely with excess capacity.

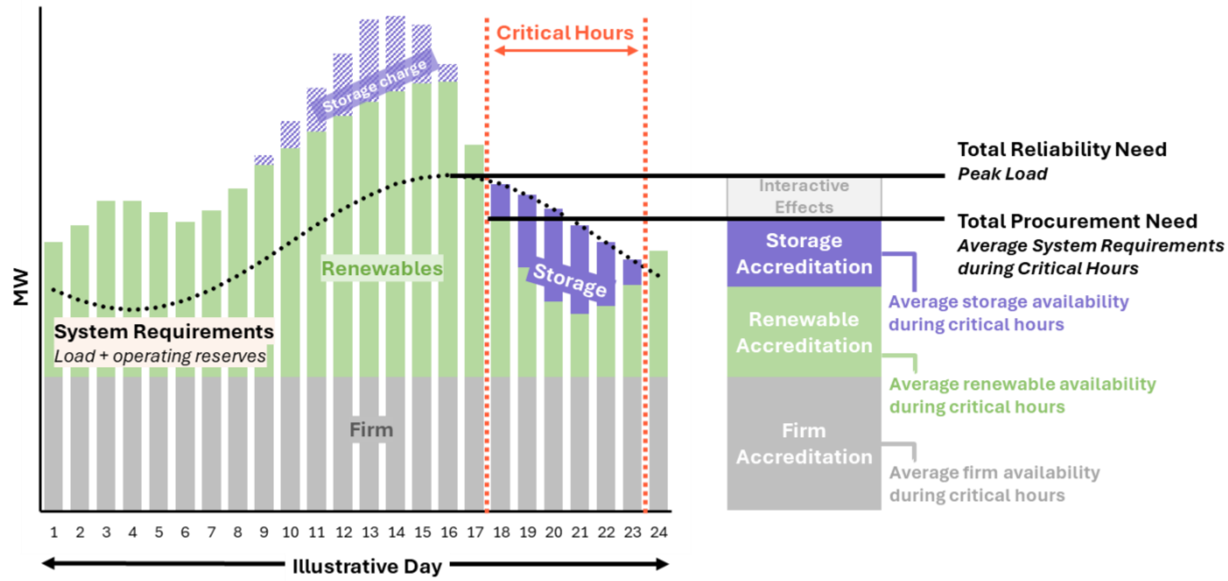


Figure 14: *Stylized illustration of the critical periods framework and the relationship between Total Reliability Need and Total Procurement Need*

Allocation of Total Procurement Need

In the critical periods framework, the allocation of the total capacity requirement among participating LSEs closely mirrors the inverse of capacity accreditation: each LSE is allocated a share of the total requirement in proportion to its share of system load during critical periods. This marginal need allocation should be calculated in a similar manner to a resource's Marginal ELCC, e.g., through an evaluation of how each LSE's hourly loads contribute to increased loss-of-load. A load-ratio share during critical hours is a reasonable approximation of this.

Marginal need allocation is important for providing efficient signals to loads. Just as it is critical for the capacity accreditation method to send economically efficient signals to the market about the value of adding generation, the need allocation method should send economically efficient signals to the market about the value of reducing loads and the cost of increasing them.

Allocation based on critical periods provides a direct signal to LSEs to limit or reduce loads when the system is in danger of experiencing loss-of-load, including, to the extent possible, to shift demand to periods outside of those windows. Any such shift provides a direct reliability benefit to the system, as increases in load outside of critical periods can be served by the latent capability of the resource portfolio without a negative impact to system reliability. Conversely, continuing to allocate need based on peak demand is **harmful to system reliability** by degrading the ability of loads to respond when needed most.

The importance of providing this market signal to loads will only increase over time as electric demand becomes increasingly flexible and demand-side resource participation in wholesale markets increases. As one example, some states are attempting to incentivize customers with load flexibility to consume electricity in the middle of the day when solar energy is abundant through strategies such as workplace electric vehicle charging and pre-cooling of homes. Such strategies will likely *increase* the system's peak load, which still occurs in the afternoon, but provide a net benefit to reliability by reducing load during critical hours. It is important that LSEs receive a smaller capacity allocation through such actions as opposed to a larger allocation, as would occur when allocation is based on peak loads. This dynamic is illustrated in the figure to the right.

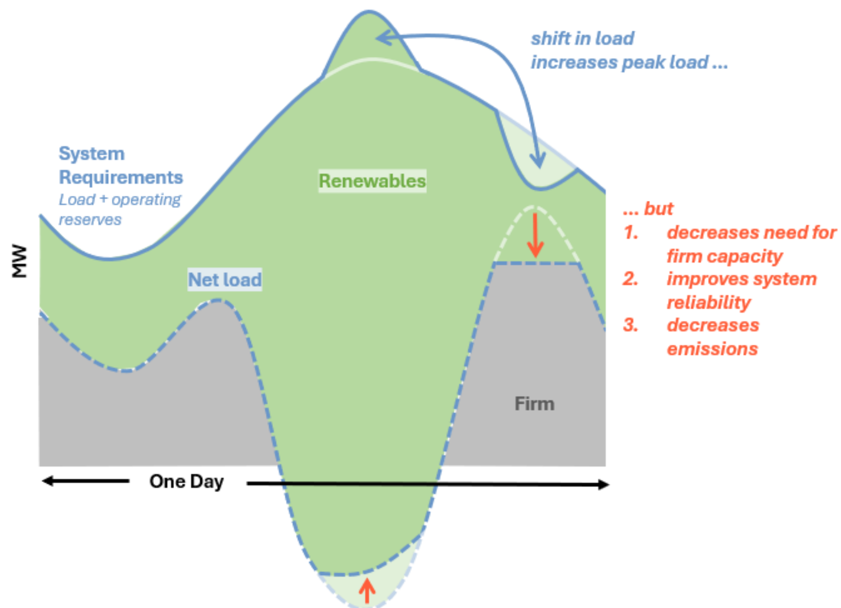


Figure 15: *Allocating need to LSEs based on peak load provides inefficient signals for operation of flexible loads*

Additionally, accreditation of demand-side programs such as demand response or flexible charging should be equivalent whether the program is treated as a supply resource or a demand reduction. Accrediting resources based on their marginal contribution to reliability improvement and evaluating loads based on the marginal contribution to reliability degradation aligns incentives and ensures that programmatic and price-based demand response are treated equivalently. Continuing to allocate need based on non-critical hours risks perpetuating a regulatory arbitrage opportunity for demand response vendors and inhibiting the efficient participation of demand-side resources.

While marginal resource accreditation is gaining widespread acceptance, as demonstrated by its adoption by NYISO, MISO, and PJM, allocation of the requirement based on relative loads during critical periods, rather than based on peak demand, remains uncommon. MISO's proposed Planning Reserve Margin Requirement (PRMR) allocation – need allocation process to LSEs based on DLOL hours – represents a first step in this direction.[25] By linking LSE obligations to historical load during these critical periods, MISO seeks to better align LSE capacity requirements to actual contribution to system risk. However, challenges remain, including volatility in historical load patterns and

[25] https://cdn.misoenergy.org/20241106%20RASC%20Item%2008b%20PRMR%20Allocation%20-%20Amended%20Nov%206658157.pdf

incomplete data on behind-the-meter generation and demand response resources, which has not allowed this proposal to be implemented yet.

Methods for Allocating Procurement Need Among LSEs

Allocating Procurement Need to LSEs first requires the decomposition of hourly system load to individual LSEs. Once this step has been performed, the modeler has the same two available methods as in the other steps of the framework

Method 1: Identify critical periods and calculate LSE loads during these periods

This step should be calculated by identifying critical periods and calculating the weighted average of LSE loads during these periods, with weights reflecting the criticality of each hour. As with need determination and resource accreditation, this method faces the challenges of appropriately determining critical hours.

Method 2: Calculate marginal load ELCC using an LOLP model

This step should be calculated as the "inverse" of a Marginal ELCC or MRI calculation using the load profile of the LSE. This is described as an inverse calculation because it uses a load profile for the calculation rather than a resource generation profile, but the mechanics are the same. Specifically, this calculation should be performed for a marginal quantity of each LSE load (e.g., their load scaled to a very small quantity) with the resulting ELCC/MRI value re-scaled up by the original reduction factor.

Additional Considerations

The values calculated above should form the basis for *allocating* system need to LSEs as opposed to directly *establishing* LSE need itself (due to the need to allocate minimum ancillary service requirements to LSEs).

A complication with the two calculation methods proposed above is that disaggregating system load to LSEs in every hour within LOLP models is not standard practice and may prove challenging. This is because LOLP utilizes dozens of weather years, and understanding LSE behavior and differences across these weather years is complex. To overcome this, it is likely that a heuristic approximation method will be necessary. One potential alternative is to allocate capacity need based on measurements of load-serving entity loads from historical years during the most constrained hours (defined as hours with the lowest incremental available operating reserves). Such an approach has the benefit of being tractable and transparent, but is also potentially divorced from future system conditions that would drive reliability risks.

4 Benefits of the Critical Periods Framework

While the previous section described many of the benefits of the critical periods framework, this section summarizes the benefits and provides additional context.

4.1 Adherence to Guiding Principles for Market Design

Market designs should seek to achieve the principles of reliability, economic efficiency, fairness/equity, and acceptability.[26] Meeting the economic efficiency principle requires the use of Marginal ELCC to provide an accurate signal about the contribution of the next increment of a given resource type toward system reliability. The critical periods reliability framework is a rigorous framework for sending appropriate signals for investment in new resources using Marginal ELCC accreditation and for incentivizing changes in load based on its impact on systemwide reliability and resource need.

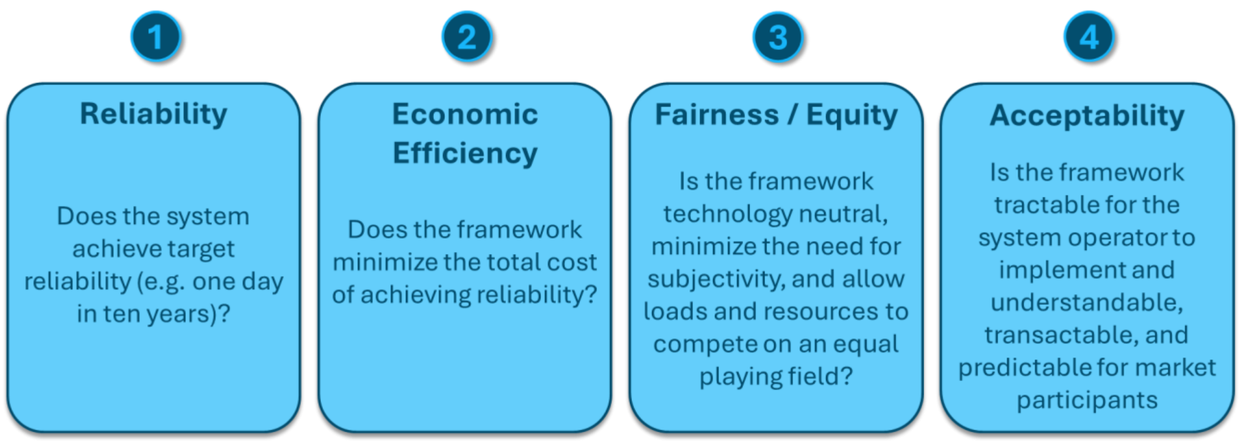


Figure 16: *Guiding principles for electricity market design*

4.1.1 Reliability

Any resource adequacy planning framework must be designed to ensure the system meets reliability requirements. A critical periods reliability framework achieves this principle by considering all hours of the year across a wide range of potential load and resource conditions (e.g., extreme weather) and identifying critical hours. An electricity system that has sufficient capacity during critical hours also has sufficient capacity in other hours, as demonstrated through rigorous modeling. This is consistent

[26] We first introduced these concepts in our prior white paper; we update them there with the benefit of several years of additional industry experience with resource adequacy and resource accreditation methods. Original white paper: Energy and Environmental Economics (E3). N. Schlag, Z. Ming, A. Olson, L. Alagappan, B. Carron, K. Steinberger, and H. Jiang, "Capacity and Reliability Planning in the Era of Decarbonization: Practical Application of Effective Load Carrying Capability in Resource Adequacy," Energy and Environmental Economics, Inc., https://www.ethree.com/wp-content/uploads/2020/08/E3-Practical-Application-of-ELCC.pdf.

with the traditional resource adequacy planning paradigm, where a system with sufficient capacity during the peak hour also has sufficient capacity in all other hours.[27]

Additionally, accrediting resources based on their marginal contribution to system reliability ensures that any substitution of one resource for another with equivalent accreditation will maintain system reliability due to the substitutability of resources on the margin.

4.1.2 Economic Efficiency

A sound market design for resource adequacy should provide efficient signals to the market for entry (i.e., new investment), retention, and exit (i.e., retirement). Additionally, it should send efficient signals to balance supply-side investments (sent through resource accreditation signals) and demand-side investments (generally sent through capacity need allocation signals).[28]

Consistent with economic theory and empirical research, price signals based on marginal cost minimize total cost.[29] A critical periods reliability framework achieves economic efficiency (i.e. the minimization of total costs) by sending marginal signals to all generating resources and loads.

Any method where accreditation is misaligned with marginal benefit incentivizes incremental investment that is uneconomic and disincentivizes investment that may be economic. As an example, any peak load-based reliability framework (such as average ELCC) will send a signal for resources to enter the market based in part on their availability during peak load hours, even if doing so will not provide any incremental reliability benefit during critical hours. This inefficient investment would increase the societal total cost of providing reliable electricity.

With respect to loads, a marginal reliability framework also minimizes costs by charging customers for capacity based on usage during the same critical hours that are used to accredit resource capacity. This incentivizes flexible shifting or load reductions during critical hours to the extent that it is more economic to do so than investing in generating resources.

4.1.3 Fairness / Equity

With respect to resource accreditation in a competitive market context, a framework will meet the criteria for fairness and equity if it is non-discriminatory; that is, it treats all loads and generating resources alike using a consistent methodology. Because a critical periods reliability framework incentivizes all loads and resources based on the same set of critical hours, the framework is

---

[27] Energy Systems Integration Group. *Redefining Resource Adequacy for Modern Power Systems*. Reston, VA: ESIG, 2021. https://www.esig.energy/reports-briefs/redefining-resource-adequacy-for-modern-power-systems/.

[28] Energy Systems Integration Group. *Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation*. Reston, VA: ESIG, 2023. https://www.esig.energy/new-design-principles-for-capacity-accreditation/.

[29] Bothwell, Anne, and Benjamin F. Hobbs. *Briefing on Regional Resource Adequacy Initiative*. CAISO Market Surveillance Committee Working Paper, June 2016. https://www.caiso.com/Documents/BriefingonRegionalResourceAdequacyInitiative-MSCBothwellHobbs_WorkingPaper-June2016.pdf.

inherently technology-neutral and creates a level playing field between all resources, including demand-side resources.

Equity considerations may have played a role to date in market operators' retention of the current method of allocating need based on peak hours rather than critical hours, as well as the use of "average ELCC" accreditation methodologies. While the critical hours approach will be increasingly important for ensuring efficient load response, changing allocation methods may result in the shifting of costs among LSEs. Changing accreditation methods may also result in changes in the value of each market participant's resource portfolio.

4.1.4 Acceptability

A critical periods reliability framework is best suited to achieve the principle of acceptability for two reasons: (1) it is tractable for the system operator, and (2) it creates an objective, understandable, transactable, and forecastable product for market participants.

From the perspective of the system operator, LOLP models that can identify critical hours (and corresponding load and resource availability in these hours) across a wide array of potential system conditions are widely used across the industry.[30]

From the perspective of market participants, these tools can be used to perform their own calculations and forecast future values using fundamentals-based approaches, just as is done today for other electricity market products, such as future energy prices using industry-standard production cost models. Additionally, a marginal reliability framework results in a single fungible product that can be transacted centrally (such as through a capacity market) or bilaterally (such as with a utility or in a decentralized capacity obligation framework), providing significant benefits from the perspective of liquidity and simplicity.

Finally, a critical periods framework provides a simple and transparent means for holding resource owners accountable for performance by establishing an expected availability during the most critical system hours. By contrast, accreditation in a peak load-based framework (including average ELCC) lacks direct physical interpretation; has been a source of confusion for regulators, operators, and market participants; and makes it difficult to evaluate resource performance retrospectively. For instance, in its root cause analysis following the August 2020 blackouts, CAISO observed that "the [California Public Utilities Commission] has improved the methods for estimating the reliability megawatt (MW) value of solar and wind over the years, but the reliability value of intermittent resources is still overestimated during the net peak hour."[31]

---

[30] EPRI Resource Adequacy Assessment Tool Guide available at https://www.epri.com/research/products/3002027832

[31] California Independent System Operator (CAISO), California Public Utilities Commission (CPUC), and California Energy Commission (CEC). *Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave*. January 13, 2021, page 6. https://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

4.2 Incorporates Both Energy and Capacity Availability

The critical periods reliability framework accredits resources by comparing them to perfect capacity. While the Total Reliability Need and Total Procurement Need are denominated in MW, not MWh, the loss-of-load modeling and resource accreditation process considers the system's need for energy across all hours of the year, as well as the ability of each resource to produce energy while accounting for any meaningful limits in its ability to do so. Perfect capacity is a theoretical resource that can be called upon to deliver energy at any time and for as long as is needed. A resource's Marginal ELCC is a measure of its ability to do so relative to perfect capacity.

This framework also simulates systemwide surpluses and shortfalls in the availability of energy, capturing the ability of energy storage to make use of surpluses for charging as well as limits on its ability to discharge due to its state of charge and round-trip losses. In fact, the elongation of critical periods due to increasing storage penetrations leads to a decline in the marginal reliability contribution of short-duration energy storage precisely *because* of its energy limitations.[32]

For example, consider an electricity system that has ample energy storage capacity but is energy deficient. This system would experience lengthy critical periods events in which energy storage resources run out of charge and energy for charging is insufficient. Capacity accreditation would be shaped by a large number of consecutive critical hours, resulting in very low accredited values for short-duration energy storage. By contrast, resources that can produce *energy* during these critical hours would receive high accredited values. This framework thereby sends efficient signals to invest in energy-producing resources and to avoid investment in energy-consuming resources such as energy storage. **The critical periods reliability framework and Marginal ELCC accreditation capture both capacity and energy sufficiency, and the relationship between them.**

Alternative forward procurement requirements have been suggested that would be denominated in MWh instead of MW.[33] While these mechanisms are not spelled out in sufficient detail in the literature to specify a detailed treatment like this paper gives to the critical periods approach, the specification would need to address the same fundamental physical challenges we consider here: the expected frequency, duration and magnitude of periods of high load and low resource availability and the temporal patterns of such events. **An energy product is simply a capacity product with a defined duration.** Moreover, denominating the forward procurement requirement in MWh would require a number of important decisions:

+ **Timing:** Should forward energy products be specified by time windows? What would the time window be and how would it be determined?
+ **Coverage:** How much of an LSE's energy requirements would need to be covered with forward procurement? Even requiring 100% of average annual energy needs to be covered

[32] Schlag, et al. "Moving Beyond Rules of Thumb for Smart, Cost-Effective Storage Deployment." *Utility Dive*, April 15, 2019. https://www.utilitydive.com/news/moving-beyond-rules-of-thumb-for-smart-cost-effective-storage-deployment/553674/.
[33] Wolak, Frank A. "Long-Term Resource Adequacy in Wholesale Electricity Markets with Significant Intermittent Renewables." *NBER Working Paper No. 29033*, July 2021.

with forward procurement may not be sufficient to ensure that the system is reliable during high net load events that are not expected to occur on an annual basis.

+ **Duration:** How would the duration requirement for the energy product be determined? Would the energy product require delivery during consecutive hours to address the potential for an extended system shortfall?

The critical periods framework avoids the need to make potentially arbitrary decisions about the nature of an energy product; instead, its parameters are derived from fundamental analysis of critical events, how loads and resources perform during them, and the desired reliability standard. Resources are accredited based on their unique characteristics, including their ability to deliver energy when needed; resources that can provide more energy during critical periods receive higher accreditations.

4.3 Creates a Standardized, Tradable Resource Adequacy Product

The critical periods reliability framework promotes market efficiency and enhances the ability of LSEs to hedge forward procurement obligations through its accreditation of all resources using a standard product: effective megawatts, derived using the Marginal ELCC methods described above. All accredited megawatts are identical, whether from solar, battery storage, nuclear generation, or accredited demand response. The accreditation process mints a common currency that market participants can exchange bilaterally to balance their positions and hedge their financial risks.

Effective forward hedging requires that both the buyer and the seller be able to reasonably anticipate potential price movements in the spot market. This requires a **well-formulated, fundamentals-based spot market** against which the forward contract can settle. Recent experience with changing accreditations in U.S. capacity markets is primarily due to experimentation with alternative accreditation methods in search of a durable, fundamentals-based solution. The critical periods framework is such a solution, and its widespread adoption should improve the stability and predictability of resource accreditations and the ability of LSEs to hedge going forward.

It is true that asset owners and LSEs will not have 100% certainty about the future accredited values of a given resource, since the accreditations are portfolio-dependent and the future system portfolio cannot be known with 100% certainty. However, the accreditations derive from a process that is based on power system fundamentals, meaning that they can be reasonably projected using fundamentals analysis of the type described in this paper. Moreover, accreditations are likely to evolve relatively slowly, since there are practical limitations on how fast the market's resource portfolio can evolve. Market participants already project revenues based on forecasts of energy prices, meaning that they already rely on forward projections of how the market-wide portfolio will evolve.

4.4 Alignment with Other Capacity Reservation Products

Resource adequacy capacity is just one of several different capacity reservations that are utilized in organized wholesale electricity markets. **Ancillary services** are capacity reservations procured primarily during the day-ahead market settlement and refined on the day-of and during the real-time market settlements. Like resource adequacy capacity, ancillary services require physical accreditation to ensure that the resources are capable of providing the services for which they are procured. The table below identifies different types of capacity reservations used in wholesale electricity markets and briefly describes the physical accreditation methods.

These capacity reservations are needed in today's markets to ensure that the system has enough physical capabilities to preserve reliability, while promoting market efficiency by clearing payments for these services through competitive bidding at prices that reflect the marginal change in total system costs. In the future, if energy storage penetration increases substantially and it becomes more possible to leverage real-time load flexibility in spot electricity markets, it is possible that such capacity reservations will no longer be needed. The market would organically signal this by clearing at low or zero prices due to lack of scarcity, both for resource adequacy and ancillary services.

Capacity Reservation Type	Description	Accreditation Methodology
Resource adequacy capacity	A physical option held by the system operator to call on energy production during periods with critical supply shortfalls	Marginal Effective Load-Carrying Capability calculated using LOLP Model
Contingency reserves, a.k.a. spinning and non-spinning reserves	Physical options held by the system operator to call on energy production in response to the sudden loss of large generation or transmission facilities	- Spinning reserves must be synchronized to the grid and capable of coming online within 10 minutes. - Non-spinning reserves generally must be capable of coming online within 30 minutes.
Flexible ramping reserves	Physical options held by the system operator to call on energy production in response to net load forecast error or large-timescale (5-120 minute) net load fluctuations	Emerging area within wholesale market operations, but accreditation is likely to be based on ramp rates and start times
Regulation and frequency responsive reserves	Physical options held by the system operator to call on energy production in response to small-timescale (<5 minute) forecast errors and net load fluctuations	Resources must be on automated generation control or directly responsive to frequency through governor control

Figure 17: *Capacity reservations used in wholesale electricity markets and their physical accreditation methodologies*

5 Additional Considerations

This section addresses a number of additional considerations related to the benefits provided by the critical periods reliability framework, refutation of some of the concerns raised about the framework to date, and implementation of the framework.

5.1 Resource Adequacy Metrics and Standards

There are a variety of metrics and standards that are used to characterize loss-of-load events. The most common metric in use in North America is Loss-of-Load Expectation (LOLE), which the Electric Power Research Institute defines as "the expected count of event-periods per study horizon, with an 'event-period' defined as a period of time during which system resources are insufficient to meet demand." The most common use of LOLE is to count the number of days during which loss-of-load events are observed in a simulation, and industry practice to date has largely centered around a "one-day-in-ten-years" standard: resources should be developed to ensure that loss-of-load events occur no more frequently than once every ten years. However, there is no uniform standard for the nature of these events, and there are differences in how even this standard is interpreted:

- One *event* in ten years, of any duration, even if the event lasts for more than one day;
- One *day* in ten years, meaning that an event that spans two calendar days is counted twice;
- 24 hours in ten years, or 2.4 hours per year, no matter how many events occur
- 6 hours in ten years, under the reasoning that a single event might last for six hours and shorter, less consequential events should count for less.

Other standards and metrics have been proposed, with much attention recently being focused on EUE, which captures both the depth and the duration in addition to the frequency of loss-of-load events.[34]

The methodology described in this paper can be utilized with any loss-of-load standard. The same principles and analytical steps would apply no matter which standard is selected: (1) calibrate the model to exactly achieve the standard, (2) calculate the Marginal ELCC of individual resources, (3) determine the Procurement Need based on the sum of all Marginal ELCCs in the calibrated portfolio or load plus operating reserves during the critical periods, and (4) allocate that need to LSEs based on their expected load during the critical periods.

---

[34] National Renewable Energy Laboratory (NREL). *Evolving Metrics for Resource Adequacy Assessment*. Golden, CO: NREL, 2023. https://docs.nrel.gov/docs/fy23osti/83025.pdf. Energy Systems Integration Group (ESIG). *Beyond 1 Day in 10 Years: Measuring Resource Adequacy for a Grid in Transition*. March 2021. https://www.esig.energy/beyond-1-day-in-10-years-measuring-resource-adequacy-for-a-grid-in-transition/. North American Electric Reliability Corporation (NERC). *Probabilistic Adequacy and Measures Report*. Atlanta, GA: NERC, December 2022. https://www.nerc.com/comm/RSTC/PAWG/Probabilistic_Adequacy_and_Measures_Report.pdf. Energy Systems Integration Group. *New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements*. Reston, VA: ESIG, 2024. https://www.esig.energy/new-resource-adequacy-criteria/.

5.2 Performance Assessments and Penalties

A well-functioning resource adequacy framework should seek to incentivize resources to perform consistently with how they are accredited in order to ensure that: (1) the system is as reliable as expected, and (2) resources are being appropriately compensated. One important tool in resource adequacy frameworks to ensure this is performance assessment of resources, namely through financial penalties for underperformance (and sometimes financial rewards for overperformance). This feature provides financial recourse for loads if purchased capacity is over-accredited and does not perform as intended.

One key benefit of the critical periods reliability framework is that capacity accreditation values represent expected generation of resources during critical hours, which can be directly compared to physical generation when these hours occur. Resources that underperform should be held financially accountable through claw-back of forward capacity payments and, if due to resource owner negligence or malfeasance, additional financial penalties.

A challenge to such an approach is that critical periods by definition occur very infrequently in a reliable system. There are two general categories of options to address this:

+ Assess and penalize resources **only during rare critical hours**. This might mean that financial penalties would need to be large enough to claw back multiple years' worth of resource adequacy compensation.
+ Assess resources **more frequently during "near-critical" periods** with more moderate financial penalties for underperformance. This option creates the potential for a disconnect to exist between the conditions during actual, infrequent critical periods that drive the greatest reliability risks and the periods during which resources are assessed for performance. For example, this could mean that a resource that performed well during a mild cold weather event one year but did not perform well during a more severe cold weather event the following year would face a lower financial consequence than under the first option.

Design and application of performance penalties is likely to be an ongoing area of research and evolving practice. It is sufficient for the purpose of this paper to note that the critical periods reliability framework is designed to align with evolving performance needs, and misalignment will happen only to the extent that such events are not foreseen by fundamentals-based power system modeling.

5.3 Addressing Common Concerns

As the industry has grappled with the appropriate framework for determining capacity need and resource accreditation in recent years, a variety of perspectives have been put forth regarding different frameworks – most notably the debate around whether marginal or some form of "average"

ELCC is the appropriate metric to use in resource capacity accreditation.[35] Detractors of a critical periods reliability framework (and equivalently a Marginal ELCC framework), have raised several concerns that we address in turn in this section.

5.3.1 Concern: a critical periods reliability framework could yield a total capacity need that is lower than peak load, resulting in a 'negative planning reserve margin'

The traditional planning reserve margin is calculated as the total capacity need divided by the median peak load. The PRM has been a convenient shorthand method for evaluating the resource adequacy of a portfolio consisting entirely or primarily of conventional, firm resources, but it has always been a derivative calculation starting from the Total Reliability Need and is not strictly necessary for maintaining resource adequacy.

As described above, the Total Reliability Need and Total Procurement Need are key elements of the critical periods framework; the Total Procurement Need is by definition lower than the Total Reliability Need and may be *much* lower than the median peak load on systems with high variable energy resource penetration. This does not imply a "negative PRM" but rather simply reflects the fact that periods of reliability risk will eventually shift to periods where demand is lower than the gross peak – and when it does, the Total Procurement Need will also be lower than the gross peak. The most appropriate PRM to use with the critical periods framework is the PCAP PRM, which is defined as the Total Reliability Need divided by the median peak load, minus one, and is always positive. However, the PRM is not strictly necessary to determine the Total Procurement Need, which can be inferred directly from loads during the critical periods, and a portfolio procured to meet the Total Procurement Need will also meet the Total Reliability Need, as demonstrated above.

5.3.2 Concern: the Procurement Need in a critical periods reliability framework is dependent on the resource portfolio

Under the critical periods framework, the Total Reliability Need is defined in a manner that is independent of the resource portfolio, providing an indication of total system need based only on load and operating reserve needs. It is true that the Total Procurement Need under the critical periods reliability framework depends on the resource portfolio, just as it does under a conventional ICAP PRM methodology. However, the critical periods framework accurately captures the performance of resources during critical hours independently and in combination, in contrast to the ICAP method, which assumes all resources are alike and independent. The critical periods reliability framework accurately reflects that the hours in which reliability risk is highest depend increasingly on both the characteristics of system load and the resource portfolio.

In a peak-based reliability framework such as ICAP, the total capacity need is *also* portfolio dependent: if the portfolio consists of resources with high forced outage rates, or if the method used

[35] Energy Systems Integration Group (ESIG). *Webinar: Ensuring Reliability with a Transforming Fleet – The Average vs. Marginal ELCC Debate*. June 28, 2023. https://www.esig.energy/event/webinar-ensuring-reliability-with-a-transforming-fleet-the-average-vs-marginal-elcc-debate/.

to accredit variable and energy limited resources is imprecise, the ICAP reserve margin and therefore the total procurement need must be higher to ensure sufficient available resources to meet the reliability standard.

The changing resource portfolio, and its ability to perform during critical periods, is the true source of variability for any resource accreditation method. The critical periods framework aligns the accredited values with the change in the portfolio's ability to perform, whereas other methods such as ICAP mask and socialize this true source of variability.

5.3.3 Concern: a critical periods framework results in shifting values over time and does not provide the stability or predictability necessary to facilitate investment in the market

Closely related to the previous issue, this concern is misplaced for two reasons. First, capacity accreditation values under the critical periods reliability framework change relatively slowly over time as the system portfolio changes, particularly as compared to observed volatility in other areas of the electricity market. Accredited values change at the same pace as load and electricity generation infrastructure changes and generally do not change more than a few percentage points in any single year.[36] In comparison to the volatility of the energy market due to factors like extreme weather and geopolitical events, accreditation values under a critical periods reliability framework are likely to be quite stable.

Second, changes in accredited values under a critical periods reliability framework provide important signals that reflect the actual changes in the electricity system, and those values will change as quickly or as slowly as the system needs change. To the extent that resource accreditation values change over time or are uncertain in the future, this reflects the fact that their contribution to system reliability is changing over time and has uncertainty. The advent of competitive electricity markets was premised on the notion that market participants are best positioned to manage the risks associated with changes in market fundamentals. A capacity accreditation framework that does not reflect changes to the marginal value socializes the discrepancy between the physical and accredited value, requiring all loads to purchase additional capacity to make up for inaccurate accreditation.

Understanding how resource adequacy values may change will require a deep understanding of both market behavior and the policy-driven transformations of electricity supply underway across much of the country. Historically, market participants have had to take views on the future dynamics of energy and capacity markets; projecting future accreditations adds a new but important dimension. Market participants' ability to make sound decisions on behalf of their customers or investors will depend on the quality of the forecasts of capacity accreditation that they use.

[36] PJM Interconnection, L.L.C., Responses to Deficiency Letter, Docket No. ER24-99-001, pp 31-33 (Dec. 1, 2023) ("Deficiency Letter Response").

5.3.4 *Concern: a critical periods reliability framework undervalues the portfolio capacity value of all combined resources by accrediting them at their marginal value*

Economic efficiency requires resources to be accredited at their marginal value. Accrediting a resource at a value that is higher than its marginal value will result in over-procurement of that resource. The Marginal ELCC saturation effect is akin to the declining marginal utility of consumption in classical microeconomics, as seen in Figure 18. While the first MW of a given resource such as solar generation might have high value for consumers in avoiding loss of load, subsequent tranches have lower value due to saturation effects. The market clears where the marginal value of the resource to consumers is equal to the marginal cost of supplying the next unit. The total value that accrues to consumers exceeds the price paid by consumers in aggregate. The difference is the consumer surplus.

Similar dynamics already occur today in other wholesale electricity market products. For example, an abundance of solar energy reduces mid-day energy prices and the costs to consumers during these periods. The price paid by consumers and the revenues earned by solar resources are not based on a counterfactual of the system's cost without solar or of the total value that accrues to consumers. Rather, it is appropriately based on the marginal value that the solar energy provides in the electricity market for a given hour. The combination of electric energy markets clearing at the marginal energy value and forward capacity markets clearing at the marginal value of accredited capacity will provide efficient price signals for new resource investments.

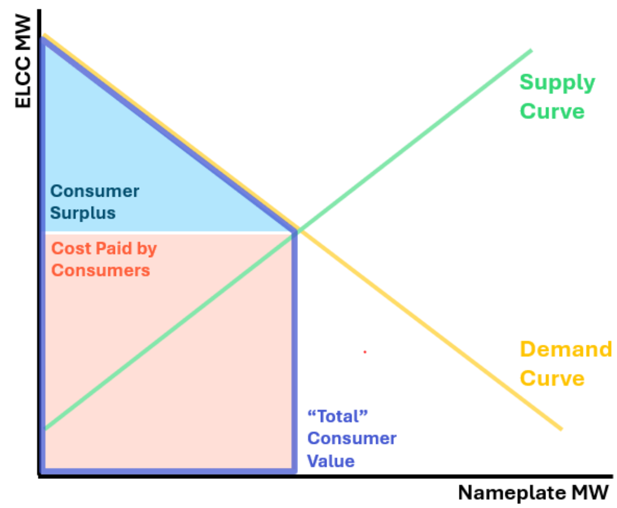


Figure 18: *Marginal valuation and consumer surplus*

5.3.5 *Concern: a critical periods framework leads to inequitable outcomes for customers who made investments in certain resources by allowing for "free riders"*

Some industry stakeholders have raised a related concern that a critical periods reliability framework facilitates "free-riding", because procurement actions taken by some load-serving entities create benefits for all LSEs. For example, procurement of solar energy by some LSEs may reduce the Total Procurement Need by shifting the critical periods into the evening hours, providing a benefit even to LSEs that did not procure solar.

It must first be noted that this argument requires the assumption of a permanent relationship between the resource and the LSE. However, a fundamental market non-discrimination principle requires that all resources must be treated equivalently, regardless of their relationship to specific electric loads.

It is true that all loads benefit from the reduced Total Procurement Need caused by resource investment that results in saturation of certain hours of the year, just as all loads benefit from lower energy prices caused by saturation. The fact that markets yield benefits through the aggregation of loads and resources is well understood and generally not characterized as free-riding. For example, the allocation of capacity need in a traditional framework (e.g., a coincident peak load allocation method) results in lower requirements than if each load-serving entity were required to procure capacity to meet its own non-coincident peak. Most market operators do not "allocate" this value to LSEs to maximize equity; rather, LSEs with load shapes that are very different from the systemwide load shape receive a greater benefit than LSEs with load shapes that are similar to the system shape.

Moreover, the LSE that made such an investment *does* receive value commensurate with its investment. If the Marginal ELCC of the solar energy that an LSE procured to serve its peak load during the afternoon is reduced to zero, this can only be because the afternoon period is saturated with solar energy and that period is no longer relevant in determining the LSE's allocated capacity need.

Finally, attempting to remedy this perceived inequity through non-marginal resource accreditation schemes would necessarily yield economically inefficient and discriminatory outcomes. For example, assigning some resources higher accreditation because of their association with specific loads (or perhaps their installation year vintage) would be discriminatory because it would accredit otherwise identical resources differently based on their ownership or contractual relationship. This approach has been rejected by FERC in prior rulings.[37] An average ELCC framework might appear to mitigate this issue by treating resources equivalently, but is economically inefficient because it over-accredits resources relative to the value they provide for system adequacy.

5.4 Practical Considerations for Resource Accreditation

5.4.1 Use of Resource Classes in Accreditation

In theory, each resource in an electricity system has a distinct and unique marginal capacity accreditation value that reflects its specific operating characteristics and limitations. In practice, due to both data availability and computational limitations, it is impractical to evaluate each resource entirely independently. In particular:

- Historical data for new, recently installed, or recently modified resources is either unavailable or insufficient to characterize their performance during critical periods in a robust manner.
- LOLP simulations are computationally intensive and impractical to repeat for hundreds of resources independently (as theoretically needed to evaluate Marginal ELCCs).

[37] Federal Energy Regulatory Commission (FERC). *Order on Compliance Filing, PJM Interconnection, L.L.C., Docket No. ER21-278-001*. April 30, 2021. https://www.pjm.com/directory/etariff/FercOrders/5696/20210430-er21-278-001.pdf.

One common simplification is the use of "resource classes." In this construct, resources with similar characteristics (e.g., technology and geography) are grouped together and evaluated for their generation during critical hours as a group. Adjustments to individual resources within each class can also be made based on actual historical generation availability during conditions of system stress.[38] The benefit of this approach is increased tractability by not requiring generation profiles or characterization of every individual resource within the electricity system and by basing adjustments based on simple and transparent historical data.

5.4.2 Seasonality

The critical periods reliability framework can be implemented on either an annual or seasonal basis. The generalized framework provided in Section 3 outlines an annual implementation.

A potential benefit of segmenting the year into seasons is to provide transparency into unique seasonal reliability risks that can contribute in aggregate to annual reliability risk. In particular, growing winter risks due to more extreme temperatures, fuel supply issues, and higher loads due to building electrification are causing many electricity systems to become more dual-risk than in the past. Additionally, many resources such as wind and solar have different seasonal availabilities that can shift risk between seasons.

While segmentation of the year into seasons is not strictly necessary from a market efficiency perspective, it does provide transparency through disaggregation of reliability requirements across different seasons and a quantification of the ability of different resources to contribute to these requirements through seasonal resource accreditation values. In other words, capacity need and resource accreditation values in an annual framework are simply a critical hours-weighted average of seasonal values. Such a weighted-average value still provides an accurate signal for resource investment and load behavior but could pose challenges in performance assessment constructs since resources with different seasonal availability will necessarily outperform their annual average value in one season and underperform it in another.

Specific additional steps to implement a critical periods reliability framework on a seasonal basis are:

+ **Define seasons:** Seasons should encompass the entire year and could reasonably be defined as two or four seasons. Utilizing a two-season framework could define summer as April-September and winter as October-March. We do not recommend segmenting the year into more granular periods than four seasons. For example, utilizing a monthly framework creates false distinctions between months when risks can manifest in any month within the season.
+ **Determine seasonal reliability standards:** Seasonal reliability standards should be consistent with an annual standard and should be roughly aligned with the seasonal reliability risks for a system at target reliability. For example, a system at a target reliability

[38] Midcontinent Independent System Operator (MISO). *Resource Accreditation White Paper: Version 2.1*. 2024. https://cdn.misoenergy.org/Resource%20Accreditation%20White%20Paper%20Version%202.1630728.pdf.

level of 0.1 days/year loss of load expectation with roughly 70% of days with loss of load occurring in the summer and 30% could set seasonal reliability standards of 0.07 days/year in summer and 0.03 days/year in winter.

- **Follow identical additional steps in an annual framework:** Once seasons and seasonal reliability standards have been defined, identical calculation steps as with the annual framework can be performed on a seasonal basis for need determination, resource accreditation, and need allocation

5.4.3 Near-Critical Periods

A challenge identified earlier in this paper in implementing a critical periods reliability framework is the identification of critical hours, which by definition occur very infrequently in a reliable electricity system. This can put significant pressure on LOLP model inputs and assumptions regarding the behavior of loads and resources during once-per-decade reliability events. One potential solution to this issue is to include a larger number of hours beyond just “true critical” hours, to include hours where the system is within a certain threshold of criticality.

Not only does increasing the quantity of hours to include critical and near-critical hours reduce pressure on accurately characterizing very rare critical events, but it also potentially provides a more accurate baseline upon which resources can be assessed for performance on a year-to-year basis, because many years *will* yield near-critical hours. However, expanding hours to include near-critical hours may create a disconnect between the true capacity need and resource accreditation values within a system (as determined by true critical hours) and the calculated capacity need and resource accreditation values when near-critical hours are included. The decision to include near-critical hours should be evaluated carefully and analytically, with pros and cons of each approach considered.

It should be noted that the increasing penetration of energy storage resources will tend to cause the potential for reliability events to occur over a larger set of hours because storage can discharge at any time across its storage horizon. Moreover, the introduction of energy storage may cause some hours to become critical not because of the direct risk of a loss-of-load event, but because they are critical for charging energy storage to avoid loss-of-load events that occur later. Thus, the actual critical hours may include more hours than those in which actual loss-of-load events occur.

5.4.4 Transmission and Locational Considerations

A key feature of an efficient resource adequacy framework ensures that resources are accredited based on their ability to generate *and deliver* energy over the transmission system to loads to avoid reliability events. While many ISO/RTOs currently utilize “zonal” or “local” capacity requirements that facilitate price divergence based on transmission constraints, most do not *accredit* resources differently based on their location within the transmission system. A framework that identifies critical periods within constrained areas of the system and accredits resources accordingly is necessary to ensure full economic efficiency. Reforms to better incorporate these transmission and locational considerations is an area of active research.

However, resource adequacy and transmission security are distinct categories of bulk system reliability. Transmission security is defined as the ability of the bulk electricity system to withstand sudden, unexpected disturbances (contingencies). Transmission security is typically assessed using AC power flow models that represent each individual generating unit and transmission element of the bulk electricity system (115kV and above), and these models capture the underlying physics of the transmission system, solving for active and reactive power flow balances. Due to the computational requirements associated with modeling AC power flows across the entire transmission network, transmission security is typically assessed deterministically for a "snapshot" in time by ensuring the system remains reliable under the most impactful contingencies (e.g., N-1) and during the most challenging periods.

As discussed throughout this paper, resource adequacy models perform a stochastic evaluation of the operations of the system on an hourly basis over multiple weather years. These models are already computationally intensive, and thus the introduction of more granular transmission constraints should prioritize the representation of import-constrained areas where maintaining local resource adequacy is paramount. Improved coordination between resource adequacy modeling and transmission security modeling, such as representing the evolving nature of critical periods within the selection of power flow snapshots, also remains an important area for continued research.

5.4.5 Role of Neighboring Systems in Resource Adequacy

In interconnected electricity systems, utilities and RTOs may seek to procure capacity from neighboring systems as part of their broader resource adequacy strategy. Interregional imports can provide reliability benefits by accessing surplus resources during periods of high demand or operational stress, particularly when neighboring regions experience different weather patterns or load profiles. In theory, this can allow for a more efficient allocation of resources across the grid and reduce the need for overbuilding capacity within individual balancing areas. To the extent that interregional transmission is available and external resources can be counted upon, capacity import arrangements can reduce planning reserve margins and lower costs for consumers.

However, overreliance on non-firm imports from neighboring systems introduces specific reliability risks. During widespread system stress – especially when driven by extreme weather – neighboring regions may face simultaneous shortages, limiting their ability to export capacity. For this reason, it is a common practice for utilities *not* to plan to rely on non-firm imports. While practices vary across the industry, in general utilities in areas with (a) robust interconnections to neighboring systems, (b) strong load and resource diversity, and (c) a liquid bilateral market for forward wholesale electricity trade tend to assume some amount of intertie support in their resource adequacy need determinations. For example, the Pacific Northwest region has many unique features that make it reasonable to assume some amount of import availability:

+ There is a liquid bilateral wholesale market for forward power trading centered around the Mid-Columbia trading hub.
+ The 500-kV regional power system is operated by the Bonneville Power Administration and serves as a common carrier for transactions to and from the Mid-Columbia hub.

- It has some utilities that are winter-peaking and some that are summer-peaking, facilitating seasonal exchanges that reduce the total regional need.
- There is a diversity of resources, with some utilities relying primarily or exclusively on hydroelectric power while others rely primarily on thermal generation.

By contrast, utilities in peninsular regions without strong interconnections or meaningful diversity tend not to plan to rely upon non-firm energy purchases from their neighbors.

This area presents multiple design challenges. On one hand, limiting the contribution of neighboring systems too severely may fail to capture legitimate diversity benefits and lead to unnecessary costs. On the other hand, assuming perfect availability of imports can result in reliability shortfalls if these resources fail to deliver. A wide-area resource adequacy assessment can help inform these tradeoffs by quantifying interregional transfer capabilities and simulating correlated stress conditions across systems. Ultimately, the extent to which imports can be relied upon should be guided by both judgment and empirical system modeling, informed by weather variability, historical flows, and outage data.[39]

If non-firm capacity from external systems is counted, it should be derated to reflect the likelihood that it will be deliverable when needed. A well-designed adequacy framework should explicitly account for these risks by aligning the accredited contribution of imports with probabilistic assessments of their availability. This may involve conservative assumptions, such as modeling neighbors to their own adequacy criteria or limiting the share of a region's needs that can be met through imports. In the absence of quantitative evidence that imported resources will be available when they are needed most, it is reasonable for a power system to plan to rely only on resources with a contractual obligation to perform.

[39] Energy Systems Integration Group. *New Resource Adequacy Criteria for the Energy Transition: Modernizing Reliability Requirements*. Reston, VA: ESIG, 2024. https://www.esig.energy/new-resource-adequacy-criteria/.

Appendix: Detailed Mathematical Formulations

In this appendix, we develop a detailed mathematical framework of ELCC and related concepts, which we use to support or clarify several of the claims made in the main body of the report. Our hope is to provide a precise framework with which to analyze ELCC in any context or application. First, we provide mathematical definitions of portfolio ELCC and marginal ELCC in terms of the "reliability function" of a power system - a notational stand-in for the LOLP model used in assessing power system reliability and resource reliability contributions. We then show the validity of certain calculation approaches outlined in the main body of the report, such as for calculating incremental and marginal ELCC. Furthermore, we state necessary and sufficient conditions under which certain important mathematical properties of the ELCC function hold, including monotonicity (non-decreasing-ness) and concavity. Finally, we extend our mathematical framework to define the reliability contributions of portfolios of loads in addition to resources. We further develop some of our claims using this extended ELCC framework.

A.1. Definition

We now state several definitions related to ELCC, which we shall use to prove some of the claims made in the paper. Implicit in the definition ELCC is the use of a loss-of-load-probability (LOLP) model to evaluate the reliability of a power system. The reliability of the system as measured by the LOLP model is generally a function of (a) the portfolio vector $x \in \mathbb{R}^n$, which contains in its entries the nameplate capacities of each resource class $i = 1, 2, \ldots, n$, and (b) the quantity of perfect capacity $C \in \mathbb{R}$ added or removed from the system. The system's peak load $L \in \mathbb{R}$ is typically assumed to be static or fixed, though it can be useful to think of system reliability as a function of peak load as well.

Let us define the **reliability function** of the power system as $m : \mathbb{R}^n \times \mathbb{R} \to \mathbb{R}$, which maps a portfolio vector x and a perfect capacity level C to a single reliability metric value $m(x, C)$. Within ELCC calculations, the LOLP model serves as the reliability function (or as an approximation thereof). Its purpose is to calculate the reliability of any power system configuration (x, C). We make no assumptions about the reliability function other than that it is continuous.

ELCC is always calculated with respect to a reliability standard $m^* \in \mathbb{R}$, which is the nominal target reliability level of the system. The reliability standard m^* is fixed throughout all calculations. A power system configuration (x, C) is considered adequately reliable if $m(x, C) \leq m^*$. A portfolio x is considered adequately reliable if $m(x, 0) \leq m^*$.[40]

[40] We use the term **system configuration** to denote a resource portfolio in combination with some amount of perfect capacity, (x, C), so as to distinguish it from a pure **resource portfolio** x.

To rigorously define the portfolio ELCC function, we first define the **capacity shortfall** function $s : \mathbb{R}^n \to \mathbb{R}$:

$$s(x) := \min\{C : m(x, C) \leq m^*\}$$

which measures the minimum level of perfect capacity C required to make the system equipped with portfolio x adequately reliable. Note that the capacity shortfall of a portfolio x may be negative if $m(x, 0) < m^*$. The portfolio ELCC function $f : \mathbb{R}^n \to \mathbb{R}$ is defined in terms of the capacity shortfall function:

$$f(x) := s(0) - s(x)$$

Here, $s(0)$ is the **Total Reliability Need** ("TRN"), i.e., the minimum level of perfect capacity needed to make the system reliable if equipped with no resources. Therefore, portfolio ELCC measures the ability of portfolio x to fulfill the total reliability need; i.e., the portfolio's ability to offset the amount of perfect capacity needed to achieve reliability.

Finally, **Marginal ELCC** is defined as the gradient of the portfolio ELCC function, or the negative gradient of the capacity shortfall function: $\nabla f(x) = -\nabla s(x)$.

A.2. Incremental ELCC

Observe that these definitions are consistent with the process of calculating the incremental ELCC of a resource addition Δx to a portfolio x:

1. Calculate $C_0 = s(x)$, the capacity shortfall of the base portfolio x, such that $m(x, C_0) = m^*$.
2. Add the resource addition Δx to the base portfolio: $x + \Delta x$.
3. Remove perfect capacity until $m(x+\Delta x, C_1) = m^*$. In other words, calculate $C_1 = s(x+\Delta x)$.

The incremental ELCC of the resource addition is $C_0 - C_1 = s(x) - s(x + \Delta x) = f(x + \Delta x) - f(x)$, i.e., the change in portfolio ELCC due to the resource addition.

A.3. Marginal ELCC

Although marginal ELCC is defined as the gradient of the portfolio ELCC function $\nabla f(x)$, here we derive an equivalent expression for marginal ELCC in terms of the partial derivatives of the reliability function. We derive this expression via implicit differentiation of the reliability function. Observe that for any portfolio x,

$$m(x, s(x)) = m^*$$

Taking the partial derivative of both sides with respect to x_i gives

$$\frac{\partial m}{\partial x_i} + \frac{\partial m}{\partial C}\frac{\partial s}{\partial x_i} = 0 \quad \Longrightarrow \quad \frac{\partial s}{\partial x_i} = -\frac{\frac{\partial m}{\partial x_i}}{\frac{\partial m}{\partial C}}$$

Therefore, marginal ELCC is the gradient of the reliability function with respect to x divided by its partial derivative with respect to C.

$$\nabla f(x) = \frac{\nabla_x m(x, C)}{\frac{\partial}{\partial C} m(x, C)}$$

This definition is consistent with a method for calculating or approximating marginal ELCC presented in the main body of this report (see *Critical Periods Reliability Framework in a Market Environment*).

A.4. Monotonicity of the Portfolio ELCC Function

An important property of the portfolio ELCC function $f(x)$ is that it is non-decreasing in x. This property holds so long as the reliability function is non-increasing in both x and C. (i.e., if resource and perfect capacity additions only improve or do not change reliability). To see this, suppose x, $y \in \mathbb{R}^n$, and $x \leq y$ component-wise. Then, for any $C \in \mathbb{R}$, $m(x, C) \geq m(y, C)$. Therefore,

$$s(x) = \min\{C : m(x, C) \leq m^*\} \geq \min\{C : m(y, C) \leq m^*\} = s(y)$$

and $f(x) \leq f(y)$, so $f(x)$ is non-decreasing in x.

A.5. Concavity of the Portfolio ELCC Function

The shape of the portfolio ELCC function is an issue of practical relevance. For instance, it is typically assumed that the marginal ELCC of a resource must decline with its penetration in the system relative to peak load. For this assumption to hold, the portfolio ELCC function $f(x)$ must be concave in x. However, it is not clear whether or under what conditions this assumption should hold. Therefore, we present the following theorem which relates the concavity of $f(x)$ to the convexity of the set of reliable system configurations, as well as to the quasi-convexity of the reliability function.

Theorem 1. *The portfolio ELCC function $f(x)$ is concave if and only if the set of reliable system configurations $\{(x, C) : m(x, C) \leq m^*\}$ is convex.*

Proof. To show the portfolio ELCC function $f(x)$ is concave, it is equivalent to prove that the shortfall function $s(x)$ is convex (since $f(x) = s(0) - s(x)$ is concave if and only if $s(x)$ is convex). Recall that $s(x) = \min\{C : m(x, C) \leq m^*\}$. Consider the epigraph of this function, which is the set:

$$\{(x, C) : C \geq s(x)\} = \{(x, C) : C \geq \min\{C : m(x, C) \leq m^*\} = \{(x, C) : m(x, C) \leq m^*\}.$$

The epigraph of $s(x)$ is the set of reliable system configurations. The epigraph of a function is a convex set if and only if the function itself is convex. Therefore $f(x)$ is concave if and only if this set is convex. □

Corollary 2. *If the reliability function $m(x, C)$ is quasi-convex, then the portfolio ELCC function is concave.*

Proof. Suppose $m(x, C)$ is quasi-convex. Then by definition all of its sub-level sets are convex, including the set of reliable system configurations $\{(x, C) : m(x, C) \leq m^*\}$. $\square$

Practically, this means that the concavity of the portfolio ELCC function is guaranteed as long as any convex combination of reliable portfolios or system configurations is also reliable, or as long as the reliability function is quasi-convex.

Note: The monotonicity and concavity properties of the portfolio ELCC function ensure that marginal ELCC values are always non-negative and decline with resource penetration. Furthermore, as long as $\frac{\partial m}{\partial x_i} \leq \frac{\partial m}{\partial C}$ for a resource (i.e., a resource may not improve reliability more than perfect capacity), marginal ELCC values will be between 0% and 100%.

A.6. Extension to Portfolios of Loads

The definitions and notation developed in this appendix may be adapted to define equivalent notions reliability value for **loads** in addition to resources. The primary challenge in doing so is to appropriately define the "magnitude" of a load, and to correctly interpret the corresponding definitions of portfolio and marginal ELCC for loads. One useful convention for defining the magnitude of a load is in terms of its contribution to the gross peak load (i.e., to the total reliability need $s(0)$). As a resource's power output profile is conventionally normalized by its nameplate capacity, a load profile may be normalized by its contribution to the gross peak.

Let $x_L \in \mathbb{R}^{n_L}$ be a vector of load magnitudes (the **load portfolio**), $x_G \in \mathbb{R}^{n_G}$ be a vector of resource nameplate capacities (the **resource portfolio**), and $C \in \mathbb{R}$ be perfect capacity. The reliability function $m : \mathbb{R}^{n_L} \times \mathbb{R}^{n_G} \times \mathbb{R} \to \mathbb{R}$ now maps a system configuration (x_L, x_G, C) to a particular reliability metric value. The capacity shortfall function measures the minimum level of perfect capacity required to make the system equipped with load/resource portfolio (x_L, x_G) reliable:

$$s(x_L, x_G) := \min\{C : m(x_L, x_G, C) \leq m^*\}$$

The portfolio ELCC of resource portfolio x_G is the difference between the total reliability need of the load portfolio and the capacity shortfall of the combined load/resource portfolio:

$$f(x_L, x_G) := s(x_L, 0) - s(x_L, x_G)$$

The marginal ELCC of a resource portfolio x_G is the negative gradient of the capacity shortfall function with respect to x_G:

$$\nabla_{x_G} f(x_L, x_G) = -\nabla_{x_G} s(x_L, x_G)$$

Other partial derivatives of the capacity shortfall function have interesting and possibly useful interpretations. For instance, the gradient of the total reliability need with respect to x_L,

$$\nabla_{x_L} s(x_L, 0)$$

measures marginal contributions of individual loads to the total reliability need of the load portfolio. Under our recommended convention, load magnitude is precisely defined such that a 1 MW increase to a particular load yields a 1 MW increase in the total reliability need (i.e., the gross peak). Therefore, we

Therefore, we assume that $\nabla_{x_L} s(x_L, 0) \triangleq \mathbf{1}$, where $\mathbf{1}$ is a vector of all ones. Note that under this convention, $s(x_L, 0) = \sum_{i=1}^{n_L} x_{Li}$, i.e., the total reliability need is equal to the sum of the load portfolio vector. Therefore, $s(x_L, 0) = \nabla_{x_L} s(x_L, 0)^T x_L$.

Furthermore, the gradient of capacity shortfall with respect to x_L,

$$\nabla_{x_L} s(x_L, x_G)$$

measures marginal contributions of individual loads to the capacity shortfall of the system. This quantity is closest in interpretation to the "marginal ELCC" of load, and in fact is equal to the average magnitude of load (relative to its gross peak contribution) during critical hours. Therefore, $\nabla_{x_L} s(x_L, x_G)^T x_L$ is total load during critical hours, i.e., the net peak load.

Interestingly, the gradient of the portfolio ELCC function with respect to load combines these two quantities:

$$\nabla_{x_L} f(x_L, x_G) = \nabla_{x_L} s(x_L, 0) - \nabla_{x_L} s(x_L, x_G) \triangleq \mathbf{1} - \nabla_{x_L} s(x_L, x_G)$$

This quantity accounts for the simultaneous change to the total reliability need and capacity shortfall of the system as the load portfolio changes. Increasing total load generally diminishes saturation effects within the resource portfolio, and therefore increases portfolio ELCC, though the marginal contribution of an individual load to portfolio ELCC strongly depends on its shape, and, for a responsive load, its flexibility to reduce demand during critical hours.

A.7. Scale Invariance Properties of Extended ELCC

An interesting property of marginal ELCC is that it is scale invariant: given a load portfolio x_L and resource portfolio x_G, for any scale parameter $\lambda \geq 0$ we have

$$\nabla_{x_G} f(x_L, x_G) = \nabla_{x_G} f(\lambda x_L, \lambda x_G)$$

This property encodes the intuition that the marginal ELCC of a resource is really a function of its *penetration* relative to system load. For example, 100 MW of solar on a 1,000 MW peak load system should have the same marginal ELCC as 1,000 MW of solar on a 10,000 MW peak load system.

Equivalently, we may write:

$$\lambda f(x_L, x_G) = f(\lambda x_L, \lambda x_G)$$

To see why this is true, take the derivative of both sides with respect to x_L or x_G. A factor of λ remains on the left-hand side, and a factor of λ appears on the right-hand side via chain rule. This is an intuitive scaling law for portfolio ELCC: a system that is λ times larger in terms of both its load portfolio x_L and resource portfolio x_G will have a portfolio ELCC that is also λ times larger.

We now use this scaling law to prove another of our claims: that the portfolio interactive effects are equal to the difference between peak load and net peak load. First, we differentiate both sides of the portfolio ELCC scaling law with respect to λ:

$$f(x_L, x_G) = \lambda \nabla_{x_L} f(\lambda x_L, \lambda x_G)^T x_L + \lambda \nabla_{x_G} f(\lambda x_L, \lambda x_G)^T x_G$$

Taking $\lambda = 1$, we get:

$$f(x_L, x_G) = \nabla_{x_L} f(x_L, x_G)^T x_L + \nabla_{x_G} f(x_L, x_G)^T x_G$$

Re-arranging terms, we have:

$$f(x_L, x_G) - \nabla_{x_G} f(x_L, x_G)^T x_G = \nabla_{x_L} f(x_L, x_G)^T x_L$$

Re-writing in terms of partial derivatives of the capacity shortfall function, we get:

$$\begin{aligned} f(x_L, x_G) - \nabla_{x_G} f(x_L, x_G)^T x_G &= \nabla_{x_L} s(x_L, 0)^T x_L - \nabla_{x_L} s(x_L, x_G)^T x_L \\ &= s(x_L, 0) - \nabla_{x_L} s(x_L, x_G)^T x_L \end{aligned}$$

The left-hand side represents the difference between portfolio ELCC and total marginal ELCC - this is precisely how we have defined the **interactive effects** of a resource portfolio. We have also used our convention of defining load magnitude as gross peak load (total reliability need) contribution to re-write $\nabla_{x_L} s(x_L, 0)^T x_L = \mathbf{1}^T x_L = s(x_L, 0)$. We have already provided the interpretation of $\nabla_{x_L} s(x_L, x_G)^T x_L$ as the average load during critical hours, i.e., the net peak load. Therefore, this equation backs up our claim that the portfolio interactive effects are equivalent to the difference between peak and net peak load.