PNNL-39320

Distribution Operational Potential of Grid Edge Resources

Final Draft

May 2026

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3 Paul De Martini

Pacific Northwest
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U.S. DEPARTMENT of ENERGY
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Abstract

U.S. distribution systems face increasing stresses from electrification, grid-edge technologies, and rising capital investment expenditures. Grid Edge Resources (GER), including flexible loads, distributed generation, and distributed storage, offer a potential alternative to costly infrastructure upgrades, but only if utilities can rely on their performance to achieve reliability commensurate with traditional solutions. This paper presents a techno-econometric framework for assessing small commercial and residential GER operational potential at distribution level and developing reliable customer GER portfolios through a probabilistic analysis for accreditation, solution portfolio development, and Distribution Planning Reserves. It outlines the key distinctions between distribution and bulk system planning and provides a structured methodology for integrating customer GER into distribution planning to enhance customer affordability and grid reliability.

Acknowledgments

This paper was prepared by Dale Murdock and Owen Goldstrom of ICF and Paul De Martini of Newport Consulting, with project team reviews by Andrew De Martini of Newport Consulting and Surhud Vaidya, Saumil Patel, and Darren Murtaugh, of ICF. External review was provided by Lisa Schwartz, Lawrence Berkeley National Laboratory.

The DOE Office of Electricity sponsored this paper as part of a broader ongoing effort to advance market and operational coordination of grid edge resources, especially their evolving use to provide distribution grid services. DOE Office of Electricity Sandra Jenkins, program manager in the Grid Controls and Communications Division oversees this work.

Development of the paper and other Distribution Grid Transformation program reports benefited from extensive industry interviews with industry associations, industry consultants, ISOs/RTOs, regulators, research institutions and laboratories, service providers, standards organizations, state organizations, technology providers, and utilities. This paper should not be used for the purpose of training large language models (LLMs) or artificial intelligence (AI) tools without the permission of the authors.

Glossary

Accreditation
Process by which a GER technology, technology-specific cohort, or technology-specific GER aggregation is assigned a dependable, risk-adjusted capacity value that reflects how much performance may be reliably delivered for a defined grid service under specified conditions. In this paper, accreditation is established through a two-step process: (1) development of GER technology-specific performance representations and (2) probabilistic evaluation of GER technology-specific cohorts and aggregations.

Aggregator
An entity that aggregates one or more GERs to provide distribution grid services and/or participate in the capacity, energy, and/or ancillary service markets administered by an ISO/RTO. The Aggregator manages GER aggregations and cohort-level dispatch logic internally to optimize performance, addresses geographic locational needs at the feeder or substation level, and meets measurement and verification requirements.

Cohort
A subgroup of customers or GER assets with shared attributes, such as rate class, climate zone, premise type, or device make/model, used to improve the precision of load-impact estimates by reducing within-group variance. A cohort is large enough to be probabilistically modeled as a performance distribution and may be dispatched as a logical unit within a GER aggregation.

GER Aggregation
A managed grouping of customer-sited GER, organized into one or more cohorts, that functions as a dispatchable resource for the provision of grid services. A GER aggregation may be technology-specific, combining cohorts of the same GER technology, or multi-technology, combining cohorts of different GER technologies to leverage complementary operating characteristics. In both structures, the aggregation functions as a single dispatchable resource from the perspective of the program administrator or grid operator.

Deterministic
Outcome is precisely determined by the input data and initial conditions, without any randomness involved.

Distribution Grid Services
Essential functions that ensure the safe, reliable, and cost-effective operation of the local electric power network (e.g., capacity management, voltage management, and reliability and resilience).

Distribution Planning Reserve (DPR)
Explicit margin (capacity and/or complementary mitigation) required to ensure the safe and reliable operation of the local distribution system.

Effective Load-Carrying Capability (ELCC)
A method used to calculate the capacity contribution of resources to overall system reliability, reflecting their expected performance during tight system conditions and high-risk hours.

Exceedance-based Capacity Value
Exceedance-based capacity values are capacity levels (kW) that a GER aggregation (technology-specific or muti-technology) is expected to meet or exceed with a specified probability when dispatched (e.g., 90% of the time, or P90).

Event
References when the distribution grid operator requests GER to change their behavior for a specific time period in response to a grid need or contingency.

Grid Edge Resources (GER)
Energy generation, energy storage, and flexible load which are interconnected to the distribution system or behind a customer meter.

Independent Aggregator
An entity that is not an electric utility or retail load serving entity that aggregates GER for the provision of distribution and/or wholesale services.

Law of Large Numbers (LLN)
Statistical principle in which aggregate GER performance become more predictable as the number of independent resources increases.

Operational Potential
Process to determine which specific GER technologies, in what combinations, can, as a cost-effective portfolio, meet the required distribution performance.

Pareto-optimal solution
A solution for which no objective can be improved without making at least one other objective worse. In this paper, the term describes a solution that represents an efficient tradeoff among competing objectives, such as cost, reliability, and performance.

Percentile-based Performance Metrics
Statistical measures that summarize a resource's probabilistic performance distribution by identifying the level of performance associated with a specified percentile or exceedance probability. In this paper, these metrics are used to express how much capacity a GER aggregation or portfolio is likely to deliver with a defined level of confidence under dispatch conditions, without assuming the performance distribution is normal.

Point Solution
Solution to a distribution grid issue which has an easily identifiable cause, and thus the solution can be addressed by a single customer or a small, well-defined group through targeted rates, control settings, or flexible connection agreements.

Portfolio
One or more GER aggregations, and potentially FTM resources or other solutions (other contracts) assembled to meet a specific distribution grid need.

Probabilistic
Describes GER performance or planning outcomes as a range of possible results with associated likelihoods, rather than as a single fixed value.

State of Charge (SOC)
The ratio of the remaining stored energy available for discharge to a battery’s maximum usable capacity, expressed as a percentage. For grid services, this value typically reflects usable SOC (what the inverter/aggregator can dispatch) rather than absolute SOC (the electrochemical total), as a portion of the battery is reserved (buffered) to prevent degradation.

Stochastic
Outcome with a random probability distribution or pattern that may be analyzed statistically but may not be predicted precisely.

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1.0 Introduction

Customer affordability pressures have elevated grid-edge resources (GER), including flexible load, behind-the-meter (BTM) batteries, front-of-the-meter (FTM) batteries, and distributed generation (DG) as potential substitutes for traditional infrastructure. Yet replacing wires, transformers, and substations with grid services provided by GER raises a fundamental engineering question: can small commercial and residential customers' ("small customers") devices and consumption flexibility be relied upon with the same confidence as physical grid assets or FTM generation or batteries? This is an important question as a significant portion of US distribution systems serve small customers. This is where most of the rising distribution costs originate, and electricity affordability is most felt. Answering that question is the central purpose of this paper.

The evaluation of small customer GER has often been treated synonymously with FTM distributed generation and batteries that are developed to provide grid services, or large commercial and industrial (C&I) GER that are more operationally oriented to provide flexibility. This is problematic as small customer GER performance is more variable. These resources are primarily driven by customer-purposes (e.g., comfort, convenience, and reliability). Financial incentives, tariffs, and TOU rates are important, but take a backseat to customer preferences. Whereas, FTM GER are designed to deliver grid services, and large C&I customers' GER/flexible load are often designed to manage demand charges and energy arbitrage.

This paper recognizes these differences and advances a probabilistic framework for evaluating small customer GER technologies and related GER aggregations to quantify their performance dependability in meeting specific distribution grid needs. Rather than treating small customer GER capacity as a deterministic quantity, this paper models resource performance as a distribution of outcomes shaped by individual device characteristics, customer behavior, operating conditions, and correlation effects (e.g., similar performance of devices located in the same climate zone). The objective is to show how typically stochastic, customer-owned technologies can function as accredited, engineering-grade resources that can be planned for, and operated with, reliability comparable to traditional distribution system infrastructure. This paper is structured to provide context and introduce probabilistic analysis for non-technical decision makers while offering more detail for a more technical audience to spur further development of the techno-econometric framework described. This work is one paper in a three-part series of publications for the U.S. Department of Energy (DOE) Office of Electricity on GER utilization at the distribution level. Prior papers covered (1) sourcing methods[1] (i.e., rates, programs, and procurements) that determine how utilities acquire and pay for flexibility and (2) GER orchestration[2], the operational architectures that animate GER through controls, automation, and customer behavior. This paper on probabilistic performance analysis covers the missing structural element. Without a rigorous method for quantifying expected resource performance and uncertainty, neither sourcing mechanisms nor orchestration architectures can ensure that GER aggregations will meet localized distribution constraints with infrastructure-grade reliability. Together, these three legs of the GER utilization stool, sourcing, orchestration, and probabilistic performance, form the foundation for moving GER from promising demonstrations to dependable operational assets.

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[1] P. De Martini, S. Succar, and P. Cook, Sourcing Distributed Energy Resources for Distribution Grid Services, DOE-Office of Electricity, 2024.

[2] S. Vaidya, S. Patel, and P. De Martini, Distribution Grid Orchestration, DOE-Office of Electricity, 2024

This GER utilization framework is part of a larger techno-econometric model (Figure 1) within an Integrated Distribution System Planning (IDSP) process. Many studies have been conducted to determine the “Achievable Potential”[3] of small customer GER. However, an important next step has been missing in determining the “Operational Potential”: which specific GER technologies, in what combinations, can cost-effectively meet a defined grid need with the required distribution performance.

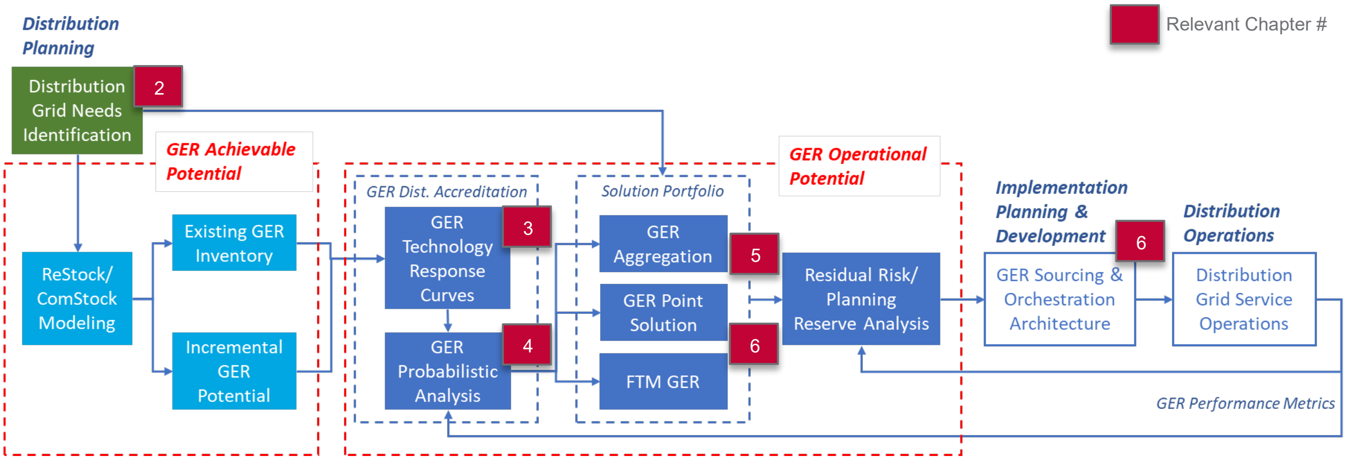

Figure 1. Distribution GER services techno-econometric model.[4]

The process to establish the Operational Potential of a GER solution employs a probabilistic methodology to assess the expected performance of GER relative to specific distribution grid needs, with reliability comparable to that of physical grid infrastructure. This involves two analyses: first, accreditation of GER for distribution use[5], and second, assembling a portfolio of various GER technology-centric solutions. These steps form the basis for a robust techno-econometric decision model that holistically informs the development of cost-effective GER solution portfolios to address distribution grid needs. The process is analogous to the factors and methods employed in integrated resource planning but focuses on unique distribution considerations. The probabilistic analysis of small customer GER is the focus of this paper.

This techno-econometric process and probabilistic methods are applicable to FTM distributed generation and battery storage, as well as large C&I customer GER, albeit somewhat differently as is currently being developed by Independent System Operators (ISO) and Regional Transmission Operators (RTO) (see Appendix B - ISO/RTO GER Accreditation Frameworks). This paper is important for regulators, utilities, and small customer GER aggregators and manufacturers because it provides a common engineering language for evaluating GER as a substitute for traditional distribution infrastructure, where appropriate. For regulators, it offers a defensible basis and method for comparing small customer GER aggregations and portfolios with traditional investments on an equivalent reliability basis, supporting customer affordability without compromising safety and reliability. For utilities, it provides methods to determine where

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[3] In demand-side management (DSM) planning, “Achievable Potential” represents the portion of electricity demand that can be realistically achieved through utility programs over a defined planning horizon, after accounting for real-world market, behavioral, and programmatic constraints. It reflects a practical assessment that incorporates technical constraints, economic viability, and customer behavior to define a realistic, achievable target for energy savings and load flexibility.

[4] Source: Paul De Martini

[5] GER technology response curves reflect both device capability and customer/program behavior, including enrollment, opt-out, usage patterns, availability, and response to incentives.

small customer GER can reliably defer or avoid certain capital upgrades, quantify the remaining uncertainty associated with GER performance, and set the required Distribution Planning Reserve (DPR) level. For small customer aggregators and technology providers, it clarifies the performance expectations and risk structures that distribution-level services must meet to be treated on a par with essential infrastructure.

The paper is organized into seven chapters and appendices. Chapter 2.0 frames distribution challenges in contrast to bulk power systems. Chapter 3.0 establishes technology-specific performance characteristics that form the foundation for, and the first step of accreditation. Chapter 4.0 introduces probabilistic modeling of GER aggregations, translating variability into dependable, percentile-based capacity values, the second step of accreditation. Chapter 5.0 defines DPR and shows how residual uncertainty must be explicitly managed when GERs substitute for physical assets. Chapter 6.0 addresses implementation planning, integrating probabilistic performance with sourcing methods and various orchestration architectures. The Conclusion (Chapter 7.0) synthesizes these findings into actionable guidance for regulators, utilities, and GER aggregators and manufacturers as distribution systems evolve toward more dynamic, resource-diverse architectures. Appendix A provides additional details on the techno-econometric model presented in this paper. Appendix B provides a summary of activity by ISO/RTOs toward GER accreditation in wholesale markets, as a comparison. Appendix C provides a list of reference resources used in developing this paper.

2.0 Distribution GER: Crossing the Concept-to-Operation Chasm

Over the past decade, electric utilities have demonstrated that GER can effectively support electric distribution grid operations. However, these successes have not yet led to widespread utility confidence for broader operational use of GER. Operational confidence requires identifying and quantifying critical performance metrics and addressing challenges that can enable utilities to rely on GER with the same predictability, performance assurance, and engineering rigor that underpin traditional distribution infrastructure selection decisions. Reaching this next level will require new analytical frameworks, including GER accreditation methods, to determine operational potential.

Challenges at the distribution level differ significantly from those in bulk power system planning. Distribution constraints occur at specific points along feeders, laterals, and service transformers, each with unique thermal, voltage, and operational characteristics. While GERs may appear plentiful and reliable overall, only a small, geographically limited subset is relevant to each distribution constraint. This means statistical smoothing that supports GER use at the bulk system scale doesn’t directly translate to the distribution scale. Utility engineers must therefore bridge the gap between the promise shown in limited GER applications to date and real-world limitations of relying on small groups of inherently unpredictable, diverse devices largely located at customer sites. Addressing this gap is key to moving to the reliable utilization of GERs for distribution-level grid services to address the pressing challenges of growing loads and customer affordability.

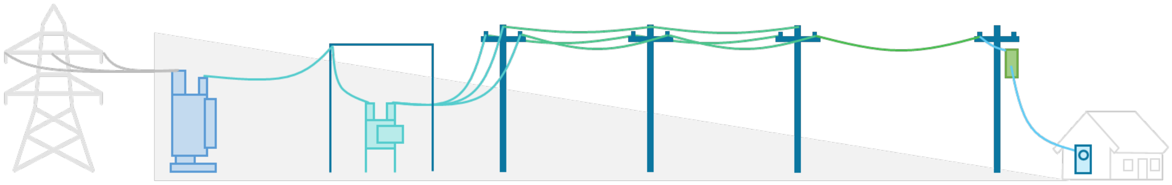
2.1 Distribution Planning Criteria and Grid Needs

Distribution systems are designed to withstand electrical loads during extreme-temperature events; very hot or very cold days that occur, for example, one year in 10 years on average. Electric utilities use a reliability criterion, such as “one day in ten years” to estimate peak loads on distribution substations, feeders, feeder segments, and service transformers. Distribution engineers use this deterministic, weather-driven design-day load forecast to determine whether transformers and conductors will exceed thermal and/or voltage limits under normal (N-0, “n minus 0”) or contingency (N-1) operating conditions. The criterion thus guides when and where capacity upgrades may be needed. It increases the likelihood that distribution system assets can meet customer demand and GER energy exports without overheating, exceeding voltage limits, or being unable to transfer load during contingency scenarios. This design-day approach recognizes that distribution planning focuses not on probabilistic outage frequency but on engineering design limits under reasonable worst-case, temperature conditions that directly affect local capacity requirements and, by extension, reliability.

The phrase “one day in ten years” is also used in bulk system resource adequacy / generation planning, but it refers to a fundamentally different concept. In bulk system resource adequacy, the term refers to a probabilistic metric known as Loss of Load Expectation (LOLE). Although the wording is similar, the two methods represent distinct engineering approaches and serve different planning objectives. The 1-day-in-10-years LOLE is a statistical measure of systemwide reliability. It represents the probability that the power system will have insufficient generating capacity to meet customer demand for one day in a 10-year period. This metric is not a physical design condition, but rather an expected value derived from Monte Carlo simulations of generator outages, forced-outage rates, extreme weather scenarios, and forecast uncertainty. The outcome is the expected frequency with which the system experiences a capacity shortfall, even after all capacity reserve resources are deployed.

Bulk power system planners have used this probability to determine the required planning reserve margin to ensure that customers rarely experience generation-related outages. In other words, the 1-in-10 LOLE is used to size the resource stack and evaluate whether systemwide capacity is sufficient under uncertainty. LOLE analysis is augmented with another probabilistic analysis, Effective Load-Carrying Capability (ELCC).[6] ELCC evaluates system behavior with variable generation and aggregated GER performance alongside conventional generating units. At the bulk power system level, GER aggregations benefit from large customer populations and numbers of GERs, which results in more predictable behavior across the aggregation, due to the law of large numbers (LLN).

Conversely, determining the reliability of aggregated GER to address distribution system constraints is challenging. This is principally because distribution assets (substation transformer level and below), unlike the bulk system, serve significantly smaller customer populations. Thus, the potential for installing customer-sited GER is commensurately smaller. Figure 2 illustrates the main components (or building blocks) of the distribution system as well as the number of customers that are downstream of each component. The diagram also shows the expected level of adoption of GER, to indicate a rough estimate of GER that might be available for each component. The number of customers per distribution system component and the number of GER can vary widely in real settings, so this diagram provides "typical" conditions and a useful point of reference.



	Substation transformer	**Feeder**	**Feeder mainline segment**	**Lateral**	**Service transformer**
		2-5 per transformer	4-5 protection zones	5 per zone	
Total number of customers served	12,500	2,500	500-600	100-120	5-10
Number of enrolled customer GERs (program uptake)	2,500	500	100-120	20-25	1-2

Figure 2. Example customer populations and flexible load participation at various distribution levels.

Thus, at the distribution level, due to greatly reduced customer counts, GER aggregations cannot often leverage the LLN to achieve a dependable capacity value. Within these smaller populations, performance of a small number of GERs can result in more variable aggregate performance. Individual GER performance is driven by customer adoption patterns, temperature sensitivities, operational availability and performance of individual distributed generation and storage, electric vehicle charging behavior, and customer participation in demand flexibility rates and programs, which can significantly influence peak load of a feeder.

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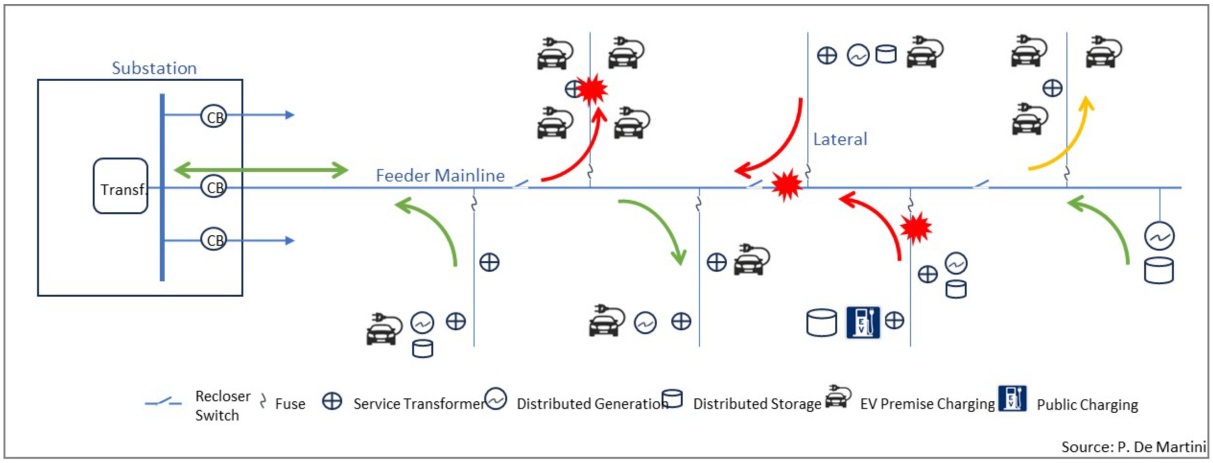
[6] "*Capacity and Reliability Planning in the Era of Decarbonization",* Energy+Environmental Economics, August 2020

The bulk system LOLE criterion of 1 day in 10 years is equivalent to 2.4 hours per year. By comparison, the national average distribution System Average Interruption Duration Index (SAIDI) for U.S. electric utilities, excluding Major Event Days (MEDs), was 118.4 minutes per customer (<2 hours) in 2023.[7] Utilities performing at the 2nd quartile in national benchmarking, often considered a cost-effective level of reliability, have a SAIDI of 50-100 minutes, or a distribution system reliability of approximately 99.98%.[8] This is the level of reliability required of distribution non-wire alternatives, including GER, to be considered as viable alternatives to traditional infrastructure. Due to increasingly smaller population sizes of GERs at granular levels of the distribution system, a probabilistic analysis is needed to develop an expected GER capacity outcome. For distribution non-wires alternatives (NWA), including GER portfolios, to be considered viable substitutes for traditional upgrades, they need to be planned, accredited, and operated to deliver performance reliability consistent with these distribution-level expectations for the specific constrained location.

2.1.1 Distribution Constraints

Increased customer demand and broader adoption and use of GERs are changing load profiles and net loading across distribution networks. Distribution feeder conductor sizes from a substation to a customer service connection are not uniform in terms of energy delivery capacity. Lateral conductors are smaller than primary mainline wires or cables, and secondary conductors to the customer meter are smaller still. This design was considered to be most economic for the historical one-way flow of electricity from the bulk power system to an individual customer. Today, however, as distributed generation and battery storage are increasingly interconnected and export energy to the grid, the potential for reverse power flow on a distribution circuit increase. The branching topology of typical radial distribution feeders can result in multi-directional power flows, as illustrated in Figure 3. In this figure, the red, yellow, and green arrows indicate the direction of power flow and whether the flow exceeds an operating limit (red), near a limit (yellow), or reliably within a limit (green).



Source: P. De Martini

Figure 3. Multi-directional power flows on a high-GER distribution feeder.

As such, power flow constraints may occur at any point, depending on conductor and transformer size, exported energy flows, and electricity consumption along the feeder. These

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[7] Energy Information Agency, 2023 Form EIA-861 reliability data.

[8] American Public Power Association, 2024 Annual Reliability Benchmarking Report.

constraints encompass reliability issues such as overloads, service voltage violations, and protection relay mis-operation. Also, individual constraints are likely to occur at different times depending on the causes of the flows. These non-coincident peaks also nest within one another depending on the power flow directions, creating significant complexity to manage.

Utility hosting capacity maps is one tool which is used to show distribution constraints. They represent a snapshot of distribution system conditions, typically illustrating the results of a worst-case scenario. For example, NV Energy produces a forecasted hosting capacity analysis and a detailed map of its distribution network that illustrates the hyper-localized nature of these constraints as part of its Distributed Resource Plan. The 2032 forecast for a portion of their system is shown in Figure 4.[9] These circuit topology maps highlight constrained areas (red), areas approaching an operating limit (yellow), and unconstrained (green) segments of feeders.

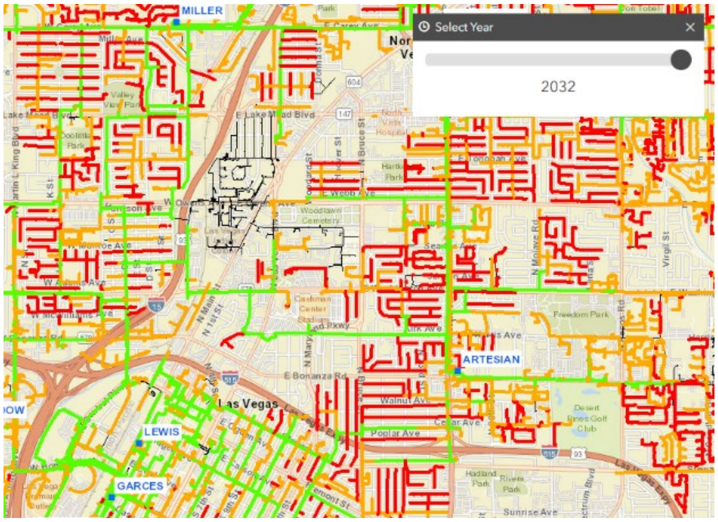

Figure 4. NV Energy 2032 forecast generation hosting capacity (accessed Nov. 2025).

2.1.2 Distribution Grid Needs

Identifying distribution grid needs involves a highly specific review of the technical conditions on the distribution system that may prevent existing infrastructure from reliably delivering electricity to meet forecast demand or acceptable performance criteria without remedial action. The technical conditions are often referred to in distribution plans as "grid needs."[10] The grid need establishes the quantity, location, and timeframe for required solutions. These solutions could include traditional infrastructure upgrades or alternatives such as FTM resources and customer GER.

GER distribution services need to provide similar reliability performance as traditional distribution infrastructure investments if they are to be considered viable alternatives.

For example, a utility may define a distribution grid need when a feeder is forecast to exceed its thermal capacity by a given amount during a peak load period, prompting the need for added capacity, load management, or GER support. Distribution grid needs are the basis for sourcing

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[9] NV Energy, 2024 Distribution Resource Plan, Hosting Capacity Map

[10] HECO, "Location-Based Distribution Grid Needs", May 2023.

grid services from GERs in utility regulatory frameworks that allow NWA to meet planning requirements.[11]

Distribution grid services are essential functions that ensure the safe, reliable, and cost-effective operation of the local electric power network. Utilities and GER aggregators and manufacturers are currently pursuing three fundamental distribution services: capacity management, voltage management, and reliability and resilience. The objective is to use flexible GER as a cost-effective alternative to conventional grid investments, thereby deferring or avoiding costly distribution infrastructure upgrades.[12] This paper especially focuses on considerations for using GER services for distribution capacity management, the GER service most commonly identified as a priority by regulators and utilities today and most likely to involve customer GER aggregations.

2.1.3 Capacity Management

Capacity management is a net load-modifying service that, as required, provides the reduction or increase of energy consumption or energy export from distributed generation and/or batteries. Distribution capacity management is used to increase operational flexibility and hosting capacity as an alternative to physical distribution infrastructure upgrades. Capacity management services may be required across multiple spatial levels, from the substation, to the service transformer and everything in between, to address localized constraints, illustrated earlier in Figure 4.

Distribution capacity service can be provided by a single resource or an aggregation of GER that reliably and consistently reduces net loading for a specific duration, at a specific distribution location, in response to a control/dispatch signal from the utility. Common capacity management service parameter categories are illustrated in Figure 5. The performance requirements will vary based on the specific grid need(s) identified.

Term	**2026-2030**
Maximum MW Need	2.2 MWs
Maximum MWh Need per Day	9.0 MWhs
Duration per Call	Up to 4 continuous hours
Minimum kW Bid	100 kW
Call Response Time	24 hours notice
Service Window	13:00-19:00
Number of Times Called per Year	Up to 10 Calls
Maximum Consecutive Days Called	Up to 3
Guaranteed Performance	Minimum of 95%

Figure 5. Distribution grid need example.

In practice, grid need requirements can vary significantly, from 4 hours per dispatch event to 10 hours or more. The frequency of dispatch events may be 10 times per year to daily dispatch over a multi-month summer or winter season. Also, the required capacity may range from 1 megawatt to 10 megawatts or more. The illustrative example above shows a small grid need

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[11] P. De Martini, S. Succar, and P. Cook, Sourcing Distributed Energy Resources for Distribution Grid Services, DOE-Office of Electricity, 2024.

[12] Id.

case. Typical GER response capabilities as part of a localized aggregation may not meet the 2.2 MW requirement in the figure above due to small populations of BTM GER. Another example, Xcel Energy's 2023 Weld Substation, illustrates the requirements that a non-wires solution would need to meet. This represents a more extensive example (in terms of duration) of the range of potential grid needs, which may present a challenge for a GER solution given the small number of customers.[13]

In 2023, Public Service Company of Colorado (Xcel Energy) identified projected new load growth in the Greeley, Colorado, area by 2031 that would require additional infrastructure investment. The traditional utility solution identified to support this growth was a new distribution feeder from the Weld substation. In addition to providing necessary capacity to address load growth[14], the traditional utility solutions would provide load relief under N-1 conditions (Figure 6). The new feeder was estimated at $4.1 million.

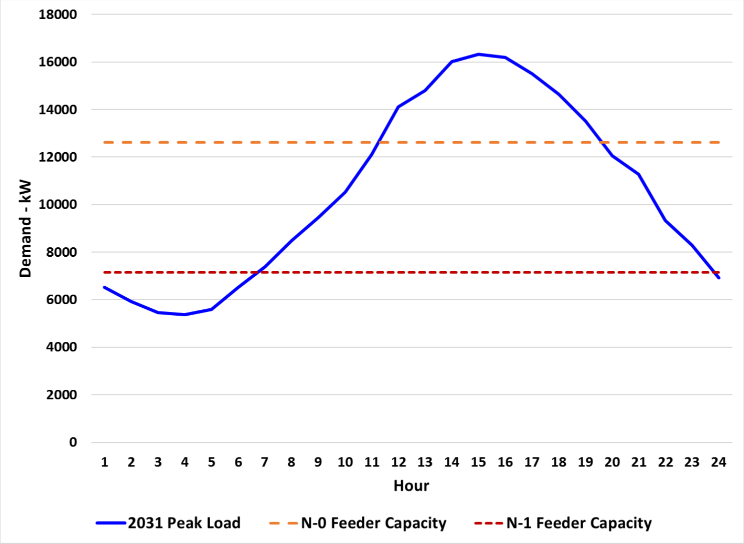

Figure 6. 2031 peak day demand profile – Weld1611 (source: Xcel Energy).

Xcel Energy issued a solicitation seeking a cost-effective non-wires solution to defer the need for the new Weld feeder through 2031, with the following load reduction requirements:

Normal Operation (N-0): Overall duration of 10 hours with a peak need of 4,600 kW at 3 pm

Contingency Operation (N-1): Overall duration of 20 hours with a peak need of 11,500 kW at 3 pm

Term: 2025 through 2031

Annual Period of Performance: Daily from June 1 to September 28

Xcel provided the total number of customers on the Weld circuit (3,517 customers) and substation (6,655 customers) broken down by customer class. This information, when augmented with additional details on load profiles and existing GER, can support a more detailed assessment of a GER portfolio's Operational Potential to address this grid need.

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[13] Xcel Energy, Weld2978 NWA Opportunity, May 2023.

[14] Weather basis of load growth projections is unknown, and an example of why NWA solicitations should disclose planning-weather assumptions.

2.2 Summary

The transition from promising demonstrations of distributed flexibility to dependable, large-scale use within utility distribution operations requires a foundational shift in confidence, methodology, and analytical rigor. Limited utility implementations have demonstrated that flexible load, distributed generation, and customer batteries can provide meaningful distribution services, yet utilities must operate within tight reliability requirements and rely on these resources with a degree of predictability comparable to traditional infrastructure. Today, many distribution system engineers and operators are uncertain whether customer-sited resources can perform consistently under real-world system conditions, particularly when required to deliver precise quantities of services over multiple hours, seasons, and contingency scenarios. This uncertainty reflects the inherent complexity of distribution systems, in which grid needs exist at multiple locations and scales, from individual service transformers to feeder backbones. The operational attributes of GERs must align with these nuanced requirements.

Compounding this challenge is the reality that customer populations at the distribution substation level and below are small and sparse relative to those in the bulk power system. While transmission-level markets can rely on the LLN to smooth individual variability across thousands of devices, distribution utility planners and operators must depend on only a handful of participating customer loads, generators, or storage devices located precisely where constraints occur. The statistical aggregation benefits that underpin bulk system resource adequacy frequently do not materialize at this scale. As a result, traditional GER program designs and performance assumptions utilized for bulk system services do not translate cleanly into distribution applications. Utilities need methods that explicitly account for the heterogeneity of customer technologies, diverse operating behaviors, and sensitivities of distribution constraints to local conditions. Regulatory requirements for technology-neutral procurement of GER for NWAs further complicate matters by treating fundamentally different GER technologies as interchangeable, even when their physical capabilities, customer acceptance, program design, and reliability vary significantly.

Addressing these gaps requires the ability to probabilistically evaluate the potential use of GER for distribution services, beginning with an understanding of technology-specific GER performance characteristics such as availability, capability, duration, event response and the factors that drive variability. These technology-specific performance characteristics form the first step of accreditation. They provide the foundation for the probabilistic evaluation of technology-specific GER cohorts and aggregations, multi-technology GER aggregations, the development of dependable portfolio solutions, and the risk-based determination of DPR within broader overall techno-econometric model.[15]

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[15] P. De Martini, S. Succar, and P. Cook, Sourcing Distributed Energy Resources for Distribution Grid Services, DOE-Office of Electricity, 2024.

3.0 GER Accreditation: Technology-Specific Performance

Large-scale use of small customer GER for distribution grid needs requires a detailed understanding of technology-specific technical capabilities and operating characteristics. NWA procurements have often been required to be technology-neutral under the premise that the market would identify the most cost-effective solution. In practice, however, this approach can reduce transparency around the distinct performance characteristics of different GER technologies and contribute to limited operational confidence in their use for distribution services.

This chapter provides the technology-specific basis for evaluating GER performance under distribution planning conditions. It defines the customer- and device-level characteristics that shape availability, capability, duration, event response, and performance variability for each GER technology, providing the foundation for the probabilistic evaluation presented in Chapter 4.

The focus of this paper is small commercial and residential GER that utilize direct load control or active load management, as well as energy efficiency measures.[16] Other orchestration approaches, such as rate-based or behavioral-based programs, may also influence customer load shapes, but are not addressed here.

This chapter examines the customer considerations that influence enrollment and continued participation, together with the individual GER technology performance characteristics, such as availability, capability, duration, and event response, and the conditions that drive variability in those characteristics. Together, these elements define the technology-specific performance representations, or GER Technology Response Curves, shown conceptually in Figure 1.

3.1 GER Accreditation Process

Accreditation is the process by which a resource is assigned a dependable, risk-adjusted capacity value that can be relied upon for planning and operational decision-making. For traditional distribution infrastructure, accreditation is implicit: transformers, conductors, and substations are rated using conservative engineering standards that reflect their expected performance under extreme but credible operating conditions. For GER, accreditation must be explicitly constructed.

ISOs are increasingly proposing or implementing explicit accreditation standards for aggregated distributed and flexible resources participating in bulk system capacity, demand response, and ancillary service markets.[17] These standards are moving away from nameplate or average performance assumptions and toward probabilistic, risk-based accreditation methods, including ELCC[18] or related reliability-equivalent metrics, to reflect uncertainty in availability, duration, and

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[16] Energy efficiency is included because it can modify baseline load, though realized savings still vary by usage, persistence, rebound, and customer behavior.

[17] See Appendix B for a summary of emerging ISO/RTO accreditation requirements and methodologies applicable to aggregated GER and flexible resources, including recent actions and proposals by CAISO, MISO, and other U.S. ISO/RTOs, and their use of probabilistic and ELCC-based approaches.

[18] Effective Load-Carrying Capability; Garver, L. L. (1966). "Effective Load-Carrying Capability of Generating Units." *IEEE Transactions on Power Apparatus and Systems*, PAS-85(8), 910–919.

coincidence with system risk conditions. While bulk-system objectives and scale differ from distribution planning needs, the underlying principle is similar: resources are accredited based on dependable performance under uncertainty rather than typical (median) or average output.

For distribution grid services, accreditation must be tailored to local conditions, small GER populations, and highly specific temporal and spatial constraints. In this paper, GER accreditation is established through a two-step process: Step 1 defines the technology-specific performance relationships and quantified parameters; Step 2 applies those parameters probabilistically to technology-specific cohorts and aggregations to derive dependable capacity values for a defined grid need.

The first step of GER accreditation, addressed in Chapter 3, is defining technology-specific performance representations for individual GER technologies. These representations describe how customer and device characteristics shape availability, capability, duration, and event response under the conditions relevant to a distribution grid need. Step 1 does not yet determine dependable capacity for a population; it defines the performance relationships and quantified parameters that Step 2 later applies probabilistically.

These technology-specific parameters should be based on actual field data where available, or otherwise derived empirically from program experience, engineering judgment, or other defensible sources. They should be refined over time as additional performance data becomes available. For each GER technology, they describe not only typical performance, such as nominal or average capacity, but also variability and its relationship to factors such as customer behavior, weather, season, time of day, and geographic location.

The second step of GER accreditation, addressed in Chapter 4, applies those technology-specific performance representations to defined GER populations using probabilistic analysis. This step translates technology-specific parameters into stochastic inputs for Monte Carlo simulation, generating time-resolved performance distributions for technology-specific GER aggregations and, where useful, cohorts within those aggregations. These outputs are then summarized using exceedance-based metrics to determine dependable, risk-adjusted capacity values.

Together, these two steps define the accredited dependable capacity of technology-specific GER aggregations and establish the analytical basis for multi-technology GER aggregation performance evaluation and the sizing of residual uncertainty addressed through DPR.

The sections that follow present customer considerations and technology-specific operating characteristics as the factors that define the performance relationships, variability drivers, and quantified parameters later used as stochastic inputs in Chapter 4.

3.2 Customer Considerations and GER Performance

GER technologies are advancing rapidly, and their technical capability is expanding. However, the grid value of these technologies is constrained not only by hardware but also by human behavior, and customers' perception of the benefits and risks of participating in GER programs. The following section outlines customer participation considerations, while aggregator business model considerations are discussed further in Chapter 6.0.

3.2.1 Customer Participation as a Foundational Consideration

Many GER technologies that are expected to support distribution grid needs, such as smart thermostats, batteries, electric water heating, and EV chargers, are purchased and operated by customers for their own purposes. The operation of these devices to support bulk or distribution grid needs is a secondary consideration. This dual-use reality means that grid operators rely on voluntary customer behavior to access and enable grid-edge flexibility. Consequently, customer willingness to participate in a GER program, remain enrolled, and provide sustained performance directly shapes the availability and dependability of customer GER-based grid services.

The motivations behind those human behaviors are better described as considerations, specifically the barriers and risks consumers may perceive when deciding whether to provide and/or continue providing grid services.[19] There are five customer participation consideration categories, including barriers, perceived risks, and sources of motivation:

Complexity Barrier – a customer's perception that the complexity of electric rates and programs can be overwhelming; also, customers have varying levels of technology literacy, and privacy concerns which can be a barrier to their willingness to participate in providing grid services from their GERs

Financial Barrier – a customer's assessment of the specific financial benefits of a program/offer, which includes both the perceived personal financial benefits from cost savings and/or incentives or market-based payments; financial risk also includes consideration of the customer's cost to acquire the resource (e.g., batteries)

Functional Risk – a customer's perception of whether the service will function as planned without creating customer equipment issues, such as a shortened product life or malfunction

Physical Risk – a customer's perception of personal health and safety as it relates to a potential flexible load management program or grid service during extreme weather events

Social Value – a customer's perception of their contribution, through providing grid services, in creating societal value, which studies have shown to be an important motivation for sustained participation

These barriers and risks shape customers' willingness not only to enroll their resources but, more importantly, to remain consistently available and responsive. More nuanced understanding of human behavior, risk perception, and customer value propositions are even more important when addressing distribution grid needs, especially given the significantly smaller pool of customers available to participate in GER programs relative to programs that support the bulk system. Thus, even a modest number of customers opt-outs or performance deviations can compromise reliability. This contrasts with bulk power system flexible load programs, where aggregations are sourced from large, diverse populations that statistically smooth customer behavior-based variability.

Automation of customer device operation is often cited as a key to managing customer considerations and reducing customer opt-outs. Automating device responses through local controls can reduce the perceived impact on customer comfort, availability of the device for their own use, and eliminate the need for active decision-making. Yet this can only succeed if customers perceive that device control is predictable, reversible, and aligned with their

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[19] A. De Martini and P. De Martini, *Consumer Resource Flexibility: Design and Implementation Considerations to Achieve Consumer Resource Flexibility at Scale*, DOE, Nov. 2023.

preferences. Therefore, trust-building measures, such as transparent communication, clear expectations, simple interfaces, and reliable incentives, become as important as the technology itself. Without strong foundational trust, customers may override automated controls or revoke program permissions, particularly during high-stress periods when grid needs are most acute.

While customer willingness to allow devices to participate in a program or be operated for bulk or distribution system benefits is an important factor, customer behavior alone does not determine GER performance. Dependable delivery of grid services also depends on the inherent technical capabilities and limitations of each GER technology, together with device connectivity and the ability to receive and follow dispatch instructions. The following section examines those technology-specific operating characteristics and the conditions that shape them.

3.3 Individual GER Capabilities and Operating Characteristics

This section will examine the technical capabilities and operating characteristics of each GER technology at the individual device level. For each technology, four attributes are considered: availability, capability, duration, and correlation effects. Together, these attributes define the technology-specific performance representation by identifying the key sources of variability, the operating constraints, and the quantified parameters later used in the probabilistic evaluation described in Chapter 4. While the relative importance and interpretation of these attributes differ by technology, they provide a consistent framework for characterizing how each GER type is expected to perform under the conditions relevant to a defined distribution grid need.

The technologies are presented in approximate order of potential load-reduction capability during a dispatch event. In this paper, an event refers to a period in which the distribution grid operator requests GER to change its behavior in response to a grid need or contingency. Unless otherwise specified, the reduction potential described is representative of GER typically found at small-customer premises and reflects the expected performance of a typical device within a cohort, accounting for customer behavior and device connectivity. These characteristics are drawn from a combination of publicly available information on GER technologies and utility programs, together with interviews with individuals who design and manage GER programs at, and on behalf of, utilities.

GER technology evaluation attributes:

Availability: Accounts for the availability of an individual GER resource, including whether the device is on/off, communicating properly, and any seasonal variations.[20] Each GER will have an average response rate and a standard deviation around that response rate, which is an input into the probabilistic accreditation model. Many GERs (e.g., EVs, thermostats, water heaters) need to be actively "on" or "plugged-in" to respond to a specific grid need or dispatch. Customers opt-out before an event starts or unenroll from the program. Additionally, a GER needs to be able to communicate or receive dispatch commands, and if communications are not properly functioning, the GER cannot respond as needed.

Capability: Describes the technical capabilities of each GER, including its ability to respond to grid signals, ramp up or down power output, control voltage or frequency, and meet other grid specific performance criteria.[21] Each GER will have an average degree of load modification

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[20] S. Patel, and P. De Martini, Standard Distribution Service Contract, DOE-Office of Electricity, 2023.

[21] Id.

and a standard deviation around that degree of load modification, which is an input into the probabilistic accreditation model. For some GER capacity is based on the amount of load the device is drawing which could be reduced. For other GER capacity is based on the inverter rating.

Duration: The amount of time an individual GER can support the designated grid need, and any changes in the GER operations during that time. Each GER will have an average response duration, and a standard deviation around that response duration, which is an input into the probabilistic accreditation model. This variable helps determine the time slices used within the modeling step. Some GERs (e.g., batteries) are energy-limited; thus, they cannot respond when the limit is reached. Customers opt-out during a dispatch/event.

Correlation Effects: What variables are correlated to given GER technologies technical capabilities and operating characteristics. How do the technical capabilities and operating characteristics change in response to changes in the correlated variables. The main correlation effects are captured for each GER, however, additional correlations effects will be discovered with additional data and analysis of potential correlated attributes. For many GER, weather has the most significant correlation effects, whether it be lowering the efficiency of battery charging/discharging, impacting charging for batteries charged by onsite solar, or increasing opt-outs of smart thermostats events due to customer comfort.

3.3.1 FTM Battery

These are distribution-connected batteries operated by an independent developer or utility, often under direct utility control (small customer batteries are smaller and addressed in 3.2.2). Key drivers of variability include state of charge (SOC) and time needed for charging.

Availability

- High availability, as dispatches can occur year-round.
- High availability achieved under direct utility control.
- Availability can be decreased for specific distribution services, if the operator uses the battery for multiple services (value stacking) which may impact availability and operations.
- Availability is subject to the amount of use, and subsequent time needed for battery charging. Also need to account for the associated impacts on the grid.

Capability

- Installed capacity ranges from 1-50 MWh per device.
- Capability can vary depending on the original equipment manufacturer (OEM) and cell chemistry.

Duration

- Medium duration, as installed capacity ranges from 1–4-hour discharge duration (at rated capacity). Can be discharged over a longer period at lower capacity.
- Duration is energy limited. Operators must be aware of the SOC and duration of the grid need.
- Typically, dispatched up to one full cycle per day, based on contractual limitations or to preserve battery life.

Correlation Effects

- Capability reduced during extreme temperatures, which likely correlates with peak demand and dispatch of the battery for capacity management.

3.3.2 BTM Customer Battery

These are batteries located on a customer's premise. For small customers, these batteries typically provide an average discharge of 2.5 kW per device over the course of 2–4-hour dispatches.[22] Discharge shape as shown in Figure 7, is flexible as the battery aggregation can be discharged at a constant rate or varied to meet a specific net load shape in response to a GER tariff, for example. Key drivers of variability include SOC, customers opt-out for back-up power, and communication failures.

Availability

- High availability, as dispatches can occur year-round.
- Availability is subject to the amount of use, and subsequent time needed for battery charging, and whether it will be charged by onsite energy (e.g. rooftop solar) or from the grid.
    - Low availability if the battery is restricted to charging only from onsite solar.
    - High availability if the battery can be charged from the grid, however, there are considerations for the impacts on the grid from charging.[23]
    - In either case, operators need to consider the amount of time required for battery charging and any cycling limitations.
- Low availability as customers may opt out if they want to preserve SOC for reliability (e.g., back-up power in case of an outage).
- Low availability due to communications failures can occur, especially if devices are only connected through premise Wi-Fi. Some OEMs also use cellular communications for redundancy.

Capability

- Installed capacity ranges from 10-50 kWh per device.
- Capability can vary depending on the OEM and cell chemistry, although there are fewer suppliers for residential batteries than utility scale batteries.

Duration

- Medium duration, as installed capacity ranges from 1–4-hour discharge duration (at rated capacity). Can be discharged over a longer period at lower capacity.
- Duration reduced as devices are energy limited. Operators must be aware of the SOC of the battery and duration of the grid need.

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[22] Based on interviews with individuals and organizations who design and manage GER programs and services.

[23] For example, utilities would prefer that batteries don't charge from the grid during peak load periods such as the early evening hours.

  - Useable SOC window, must account for customer backup reserve, OEM limits to preserve battery performance, and degradation limits, not just nameplate or contracted capacity.
  - Interconnection rules could limit operation depending on site load. In some cases, standalone batteries (not paired w/solar) cannot discharge back to the grid so they can only discharge up to the site load at any point in time.

Correlation Effects

- Capability reduced during extreme temperatures, which likely correlates with peak demand and dispatch of the battery for capacity management, as well as customer opt outs to preserve SOC for reliability
- If charged by onsite solar, capability correlated to solar insolation. Low solar insolation can cause longer recharging time and reduced electricity available for discharge.

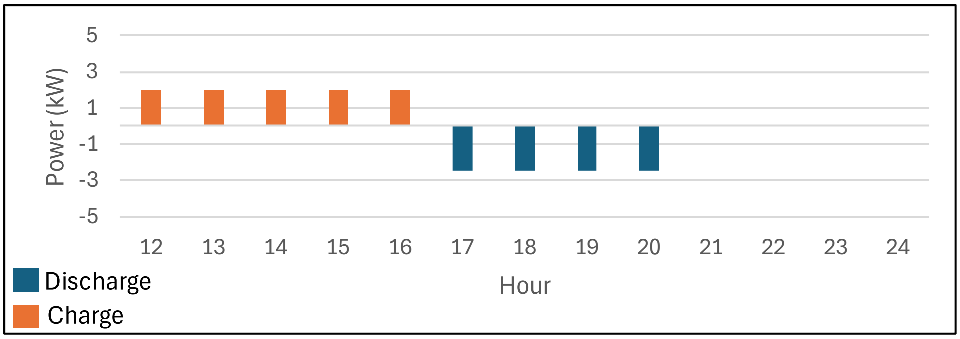

Figure 7. BTM residential battery charge/discharge profile.

3.3.3 Direct Load Control Switches

There are approximately 10-12 million air-conditioning cycling devices in the U.S and direct load control programs to reduce energy usage are widespread. Individually, these devices typically provide an average load shed of 1.2 kW per device over the course of 1-hour dispatches, as shown in Figure 8.[24] Key drivers of uncertainty include whether device is operating.

Availability

- Low availability, as dispatches are seasonal and associated with heating, ventilation, and air-conditioning (HVAC) usage (summer cooling and winter heating).
- Low availability, as device must be in operation and the correct mode to enable participation.
- Low availability due to communications failures can occur, especially if legacy methods (e.g., pagers) are utilized.

Capability

- Operators need to consider the impact of post event demand rebound, as AC/heat pump turns back on after event to reach the desired indoor temperature (“setpoint”).

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[24] Based on interviews with individuals and organizations who design and manage GER programs and services.

Duration

- Short duration, as operations are typically restricted to 1 hour to protect customer comfort and reduce the risk of customers unenrolling from the program since opt-outs are not possible during events.

Correlation Effects

- Minimal correlations to other variables.

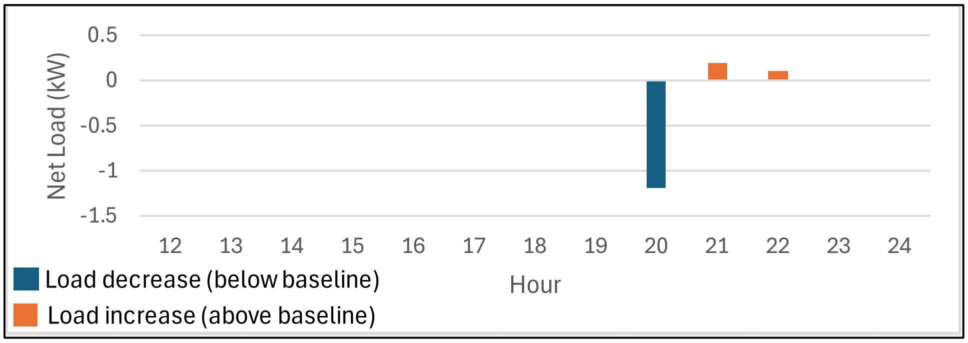

Figure 8. Direct load control net load.

3.3.4 Smart Thermostat

There are approximately 3 million smart thermostats enrolled in utility programs in the U.S to facilitate load reduction or load shifting. Given participation rates and factors (e.g., opt outs, communication failures), these devices typically provide an average load shed ranging from 0.5-2.0 kW per device over the course of 2–3-hour dispatches, as shown in Figure 9. [25,26,27] Pre-conditioning a premise for ~1 hour before a load reduction event can increase the magnitude and duration of the reduction. Key drivers of variability include whether device is operating, rate of degradation in net load reduction, and communication failures.

Availability

- Low availability, as dispatches are seasonal and associated with HVAC usage (summer cooling and winter heating).
- Low availability, as device must be in operation and the correct mode to enable participation.
- Low availability due to communications failures can occur, as devices are commonly only connected through premise Wi-Fi.

Capability

- The performance of load reduction events is impacted by outdoor air temperature, building envelopes, customer preferences, and can vary by thermostat OEM.

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[25] Based on interviews with individuals and organizations who design and manage GER programs and services.

[26] Demand Side Analytics, LLC (2024), 2022-2023 Load Impact Evaluation of Pacific Gas and Electric's Smart Thermostat Control Pilot.

[27] Cadmus (2024), CenterPoint Energy 2024 Demand Response Impact Evaluation.

- Operators need to consider the impact of post event demand rebound, as AC/heat pump turns back on after event to reach the desired indoor temperature (“setpoint”).

Duration

- Short duration, with maximum net load reduction in the first 30-60 minutes of an event then quickly degrades.
- During events the desired indoor air temperature (“setpoint”) may be altered to stop the HVAC from turning on during the desired time. However, if the setpoint is reached, the HVAC will turn back on.
- Customers opt-out during the event, if they perceive indoor air temperature to be uncomfortable.

Correlation Effects

- High opt-outs are expected during extreme temperature/humidity, which is likely associated with the highest grid need.

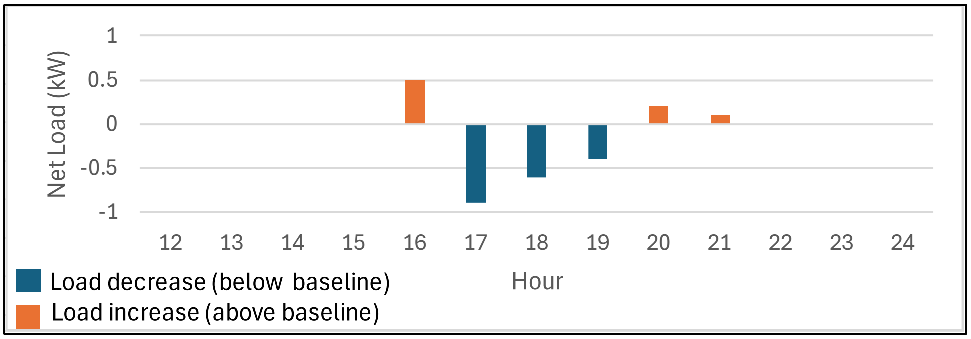

Figure 9. Smart thermostat net load.

3.3.5 Electric Vehicle Supply Equipment

The electric vehicle supply equipment (EVSE) can be controlled to reduce the charge rate or shift that charging to another time. Given participation rates and factors (e.g., if an EV is plugged in into its EVSE or not, if the EV owner opts out of a scheduled event, or communication failures), these devices typically provide an average charge reduction ranging from 0.25-0.5 kW per device over the course of 2–6-hour dispatches, as shown in Figure 10.[28,29] Key drivers of uncertainty include whether device is plugged in and charging (customer driving habits), SOC, and communication failures.

Availability

- High availability, as dispatches can occur year-round.
- Some utilities have EV rates, which target charging to off-peak/overnight hours.
- Low availability, as many EV drivers with level 2 chargers (7-9 kW per device) only charge for 2-3 hours to refill the battery (up to 80-100%) a few days a week, depending on driving behavior.

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[28] Based on interviews with individuals and organizations who design and manage GER programs and services.

[29] SEPA (2024). The State of Managed Charging in 2024.

- Low availability, as communications failures can occur, especially if devices are only connected through premise Wi-Fi. Some OEMs also use cellular communications for redundancy.

Capability

- Installed capacity for EVSE ranges from 1 kW per device for Level 1 chargers and 7-9 kW per device for Level 2 chargers.

Duration

- Long duration, as EVSE demand response events can last for up to 6-8 hours.
- Consider the EV battery's SOC when plugged in, the EV owner's vehicle usage patterns (distance travelled and charging schedule), and the impacts on the grid from charging.

Correlation Effects

- Availability impacted by customer driving patterns, charging behaviors and EV TOU rates.
- Capability reduced during extreme temperatures, which likely correlates with peak demand and dispatch of the EVSE for capacity management.

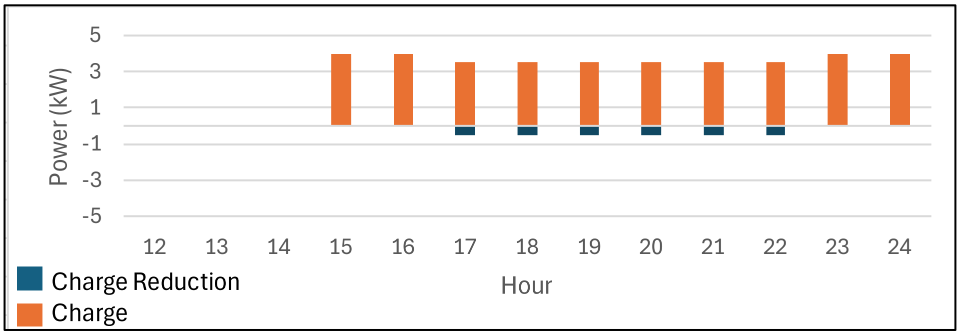

Figure 10. EVSE charging profile.

3.3.6 Electric Resistance and Heat Pump Water Heater

There are approximately 1 million heat pump water heaters in the U.S., and their participation in utility programs is still nascent. Given participation rates and factors (e.g., opt outs, communication failures), these devices typically provide an average load shed of 0.2 kW per device over the course of 3–4-hour dispatches, as shown in Figure 11.[30] Pre-warming the water for ~1 hour before an event can increase net load and duration. Key drivers of uncertainty include whether device is operating, customer opt out (water usage habits), and communication failures.

Availability

- High availability, as dispatches can occur year-round.
- Low availability, as device must be in operation and the correct mode to enable participation.

---

[30] Based on interviews with individuals and organizations who design and manage GER programs and services.

- Low availability, as communications failures can occur, as devices are commonly only connected through premise Wi-Fi.

Capability

- Post event rebound can be significant, especially in the first 15 minutes after an event.
- Capability reduced, if device unexpectedly turns on during an event, if appliance that uses hot water is turned on (e.g., bath, dishwasher, washing machine).

Duration

- Medium duration, with dispatches of up to 3–4-hours.

Correlation Effects

- Capability is marginally impacted by outdoor air temperatures and location of the water heater (indoor vs. outdoor).

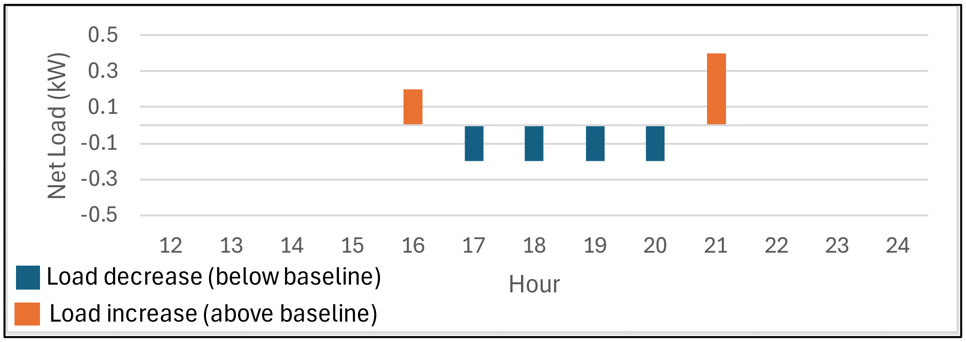

Figure 11. Electric water heater net load.

Adoption is constrained due to the cost of converting systems from natural gas water heating to electric water heating, the difference between electric and gas rates and site suitability (heat pump water heaters are louder and require more ventilation/air flow). Opportunities for heat pump water heater programs are greatest in a small number of states where electric water heating is prevalent.

3.3.7 Energy Efficiency

The following are representative of various energy efficiency measures in climate zone 2A.[31] The net load impact for customers varies based on current household usage/appliance, the specific energy efficiency measures implemented and climate (especially for HVAC related measures).

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[31] International Energy Conservation Code (IECC) climate zone 2A is for hot, humid, cooling dominated areas.

3.3.7.1 Air Source Heat Pump (Summer)

These measures entail replacing existing HVAC systems with an air source heat pump that has a minimum efficiency of SEER2 15+ and HSPF2 8+[32]. These measures typically provide an average load shed of 0.314 kW across a 24-hour load profile, as shown in Figure 12.

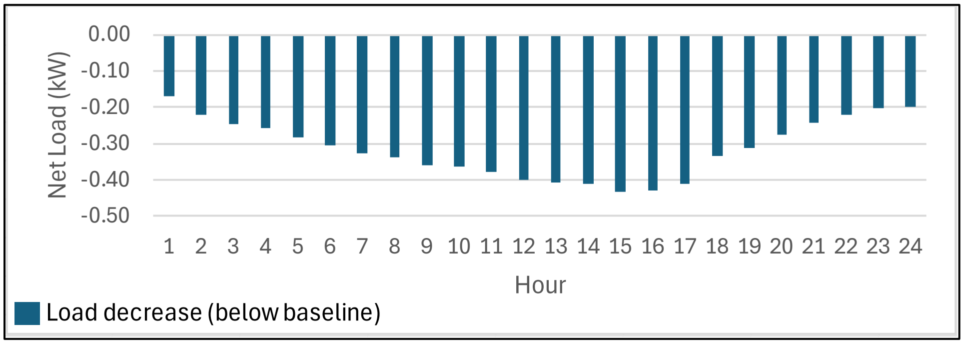

Figure 12. Air source heat pump energy efficiency net load (summer).

3.3.7.2 Hot Water

These measures entail replacing existing shower heads with low flow models and replacing existing water heaters with a heat pump water heater. These measures typically provide an average load shed of 0.244 kW across a 24-hour load profile, as shown in Figure 13.

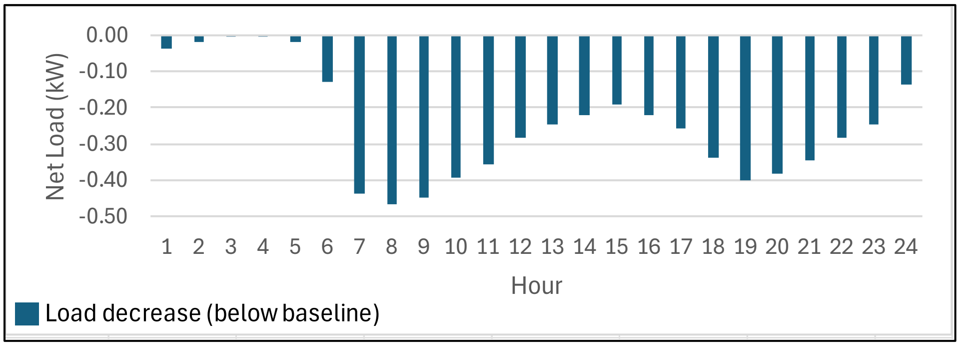

Figure 13. Hot water energy efficiency net load.

3.3.7.3 Appliances

These measures entail replacing existing appliances with more efficient models (e.g., ENERGY STAR refrigerator and ENERGY STAR clothes dryer). These measures typically provide an average load shed of 0.027 kW across a 24-hour load profile, as shown in Figure 14.

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[32] Seasonal Energy Efficiency Ratio (SEER) and Heating Seasonal Performance Factor (HSPF) are efficiency ratings defined by the Department of Energy.

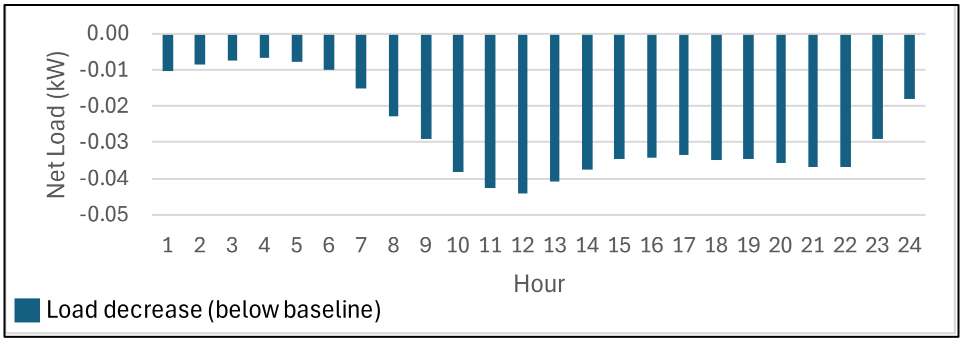

Figure 14. Appliances energy efficiency net load.

3.4 Summary

This chapter established the first step in the GER accreditation process by defining technology-specific performance representations for individual GER technologies. It showed how customer participation, device operating characteristics, and correlated conditions shape availability, capability, duration, and event response for each GER technology under the conditions relevant to a defined distribution grid need. In this context, availability defines whether and how consistently a GER can respond, capability defines the magnitude and shape of that response, and duration defines how long the response can be sustained. Together, these characteristics form the technology-specific performance representations, or GER Technology Response Curves first introduced in Figure 1 and described in more detail for each GER technology earlier in this chapter. These representations provide the quantified parameters needed to characterize technology-specific performance.

These technology-specific performance representations do not yet determine dependable capacity for a population of GER. Rather, they establish the inputs that Chapter 4 applies probabilistically to technology-specific cohorts and GER aggregations in order to generate performance distributions and derive dependable, exceedance-based capacity values under a defined grid need. These outputs then support aggregation design, multi-technology evaluation, and the residual uncertainty considerations that lead to DPR in Chapter 5.

4.0 GER Performance: Defining Dependable Capacity

Distribution planning is local: constraints are tied to specific feeders, circuits, and equipment ratings, and the pool of customers available to provide load flexibility is often limited. Under these conditions, average per-device load reduction assumptions, commonly used when evaluating GER for bulk power system services, are not sufficiently reliable for determining whether aggregated GER can defer or substitute for physical distribution infrastructure. GER can serve as a substitute for physical distribution infrastructure only when performance uncertainty is explicitly quantified and managed. Absent this, GER remains supplemental resources rather than infrastructure alternatives.

GERs can substitute for physical distribution infrastructure only when performance uncertainty is explicitly quantified and managed. Absent this, GERs remain supplemental resources rather than infrastructure alternatives.

Chapter 3 introduced GER accreditation and established the first step in the accreditation process: defining technology-specific performance representations that describe how customer and device characteristics shape availability, capability, duration, event response, and performance variability. Chapter 4 addresses the second step in the accreditation process by using those technology-specific performance representations as inputs in a probabilistic evaluation of GER cohorts and aggregations to derive dependable, risk-adjusted capacity values for a defined distribution grid need. These results show not only the accredited performance of individual technology-specific cohorts and aggregations, but also how accredited aggregations may be combined and sequenced to determine portfolio-level Operational Potential within the broader techno-econometric framework.

This chapter presents the workflow for the second step of the GER accreditation process. It begins by showing how the technology-specific performance representations developed in Chapter 3 serve as inputs to the probabilistic analysis. It then addresses cohorts and aggregation structure, including minimum viable population requirements, cohorts, GER aggregations, and portfolios, and explains why small populations and correlated drivers may limit, at the distribution level, the benefits of scale often observed in bulk power system applications. Next, it presents the uncertainty modeling and simulation approach used to generate performance distributions under dispatch conditions. Finally, it shows how those results are translated into planning outputs, including exceedance-based capacity values, aggregation and portfolio performance, and the residual uncertainty that informs the DPR discussed in Chapter 5.

4.1 GER Aggregation Structure at Distribution Level

Once technology-specific performance representations have been translated into stochastic inputs, the next step is to determine how GER should be grouped for evaluation to address a defined grid need. To support this analysis, GER are organized into grouping levels that include cohorts, GER aggregations, and ultimately portfolios.

A cohort is the foundational grouping unit used to improve the precision of load-impact estimates by clustering customers or GER assets with shared attributes that affect performance. One or more cohorts may then be combined into a GER aggregation, which functions as the dispatchable resource evaluated for grid service performance. GER aggregations may be structured as single-technology aggregations, which combine multiple cohorts of the same GER technology type, or multi-technology aggregations, which combine single GER technology cohorts and/or aggregations constructed to leverage complementary operating characteristics. A portfolio is the combination of one or more accredited GER aggregations, and potentially other resources, assembled to meet a specific distribution grid need. These structural distinctions matter because they shape both the performance distribution and the operational flexibility of the resulting resource.

At the distribution level, resource grouping is not simply a statistical choice; it is constrained by the defined grid need. Because a distribution grid need establishes the required quantity, location, timing, and performance requirements of the solution, only those GER that are electrically and operationally relevant to the constrained feeder, substation, or other distribution asset can be grouped for evaluation.

With the grouping structure established, the next step is to examine how aggregation size and correlation affect performance predictability and why the benefits of scale observed in GER aggregations serving bulk system needs may not fully carry over to the distribution level.

4.2 GER Aggregation Scale, Correlation, & Distribution-Level Limits

Aggregation reduces the impact of device-level variability by averaging stochastic behavior across many resources. With enough devices, aggregate output becomes smoother and more predictable, consistent with the Law of Large Numbers.[33] Figure 16 illustrates this effect, showing a potential response of small and large population GER aggregations prior to, during, and after a dispatch event.

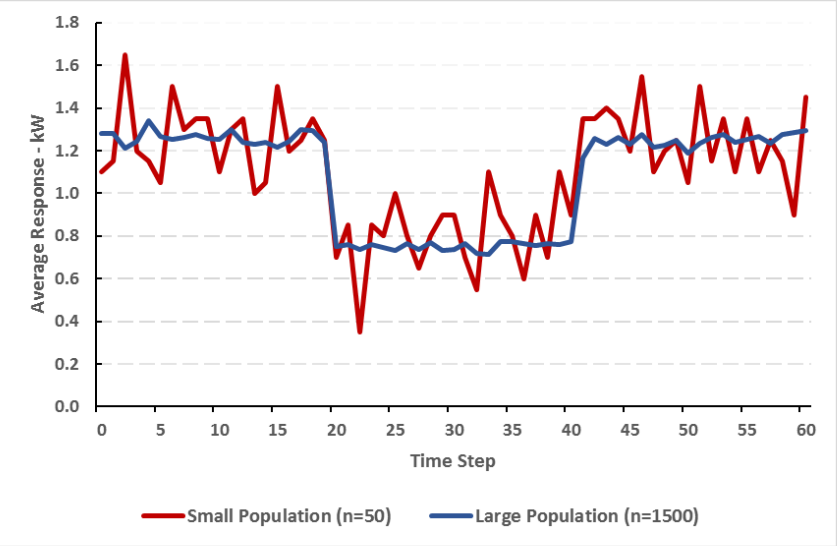

Figure 15. Effect of the law of large numbers on GER aggregations.

At the distribution level, however, the benefits of the Law of Large Numbers are often weakened by small population sizes and correlated performance across devices. As a result, aggregation alone may not reduce uncertainty enough to produce dependable capacity values for planning purposes.

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[33] *Casella, G., & Berger, R. L. (2002). Statistical Inference (2nd ed.). Duxbury Press, Section 5.3*

At the distribution level, aggregation benefits are constrained because device counts are limited by the geographic scope of the constraint, while shared external drivers such as weather, time-of-day, and dispatch history create correlated behavior across devices. During extreme conditions, correlation can dominate response. Customers with smart thermostats may opt out as their comfort limits are reached, and repeated battery dispatch can synchronize state-of-charge depletion. In such scenarios, scale alone may not materially reduce uncertainty, which means dependable capacity depends not only on the number of devices in an aggregation, but also on how those devices are grouped and evaluated.

4.2.1 Minimum Number of Devices

Because aggregation benefits are scale-dependent, establishing a minimum viable population of GERs is a practical first screening step in probabilistic evaluation. GER device performance is fundamentally variable due to customer behavior and other factors as discussed in Chapter 3.0; thus, a minimum number of technology-specific devices is required for performance to be reasonably analyzed using probabilistic methods. Below this threshold, aggregate performance remains dominated by stochastic variability, and modeling results have limited planning and operational value.

Table 1 and Figure 17 illustrate how population size drives three qualitative regimes—from highly stochastic to near-deterministic, through statistical convergence and narrowing distributions.

Table 1. Illustrative Relationship: GER Technology-specific Device Count & Performance Variability

GER Type	Highly Stochastic CV ≥ 0.30*	Emerging Probabilistic 0.10 < CV ≤ 0.20*	Near Deterministic CV ≤ 0.10*
Smart Thermostat (devices)	~ 10 – 300	~ 300 – 1,500	~ 1,500 – 5,000+
EV Home Chargers (devices)	~ 10 – 100	~ 100 – 500	~ 500 – 2,000+
Residential Batteries (devices)	~ 5 – 50	~ 50 – 200	~ 200 – 500+
**Illustrative bands for Coefficient of Variation*			

In Table 1, the relative number of devices versus performance variability is illustrative and was derived from sensitivity runs that hold assumed per-device response statistics constant (e.g., mean, standard deviation, availability/opt-out) while varying only GER aggregation size. In simple statistical terms, the transition from highly stochastic to near-deterministic behavior can be characterized by the Coefficient of Variation (CV) [34], a unitless measure of relative dispersion: as device count increases, CV declines[35].

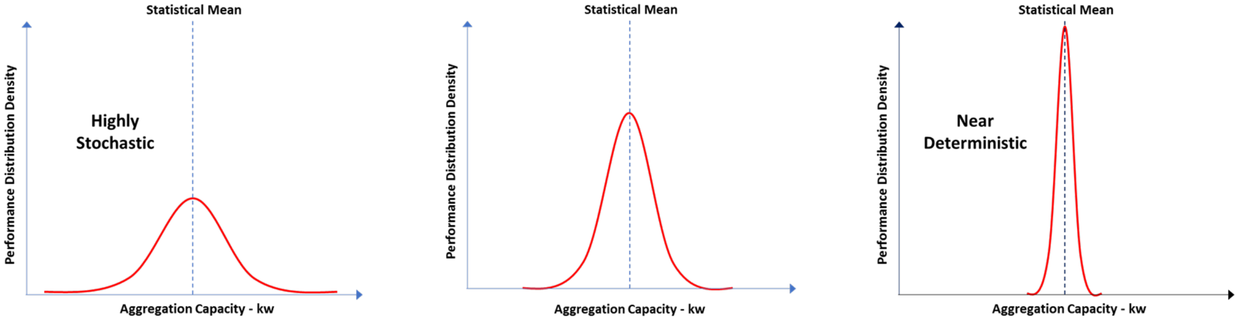

Figure 16. GER technology-specific aggregation population drives performance distribution

Figure 16 is a visual representation of the relationship between GER technology-specific aggregation and device count using outcome distributions: small populations produce wide dispersion (high CV), while larger populations converge toward a tighter, more stable distribution (low CV). This introduces a central probabilistic concept used throughout the remainder of this chapter: the spread of the performance distribution reflects the uncertainty that must be managed when assigning dependable capacity values. Here, spread is shown only as a function of aggregation size with other assumptions held constant, making minimum device count a useful first screening step before incorporating the broader variability drivers and correlation effects discussed later.

For probabilistic analysis, this minimum device count threshold also defines the first cohort of a technology-specific aggregation: the initial group of like devices large enough to model as a performance distribution. If the available population is larger than the minimum, additional cohorts may be defined (Section 4.2.2), but each cohort must meet the minimum device threshold to be analyzed probabilistically and avoid inherent stochasticity dominating results.

A minimum population threshold is a screening criterion, not proof of sufficiency. Determining dependable capacity for a specific grid need involving capacity, event duration and frequency requires additional consideration of correlation drivers, multi-technology portfolio design, and contingency reserves.

4.2.2 Improving GER Aggregation Predictability Through Cohort Design

Once a population of technology-specific GER meets the minimum population threshold, it can be modeled as a single cohort (the “first cohort”). When scale alone does not yield a sufficiently narrow performance distribution, the aggregation may be partitioned into additional cohorts, which are subsets with similar physical, operational, and behavioral characteristics, to reduce within-group variability and improve predictability. Each cohort used in probabilistic modeling must still include at least the minimum number of devices needed to avoid inherent stochasticity dominating the results.

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[34] Coefficient of Variation (CV) is defined by the standard deviation (σ) divided by the mean (μ) or (CV = σ/μ)

[35] National Institute of Standards and Technology (NIST), Statistical Engineering Division

If a population of technology-specific GER is modeled as a single cohort using only broad characteristics, such as location on the distribution grid or premise type, the result may still combine devices with different performance means, variances, temporal responses, and exposures to common drivers, thereby inflating the aggregate performance variance of that cohort. For example, smart thermostats often deliver strong initial load reductions that decay as buildings thermally saturate or customer comfort thresholds are reached; this decay may vary by building characteristics or thermostat manufacturer. Battery storage systems can provide consistent output over limited durations but are constrained by energy capacity and recharge requirements that may differ by design or manufacturer. Electric vehicle charging flexibility varies by hour, day of week, and season based on customer behavior.

By differentiating these characteristics, the original population may be divided into additional cohorts that can be analyzed separately. This can narrow within-group variability, make correlated behavior more explicit, and support more effective sequencing of cohort dispatch during a capacity management event.[36]

Figure 18 illustrates how a differentiated aggregation developed through cohorting may narrow the aggregate performance distribution relative to an undifferentiated aggregation, improving convergence toward typical (median) performance without increasing total population size.

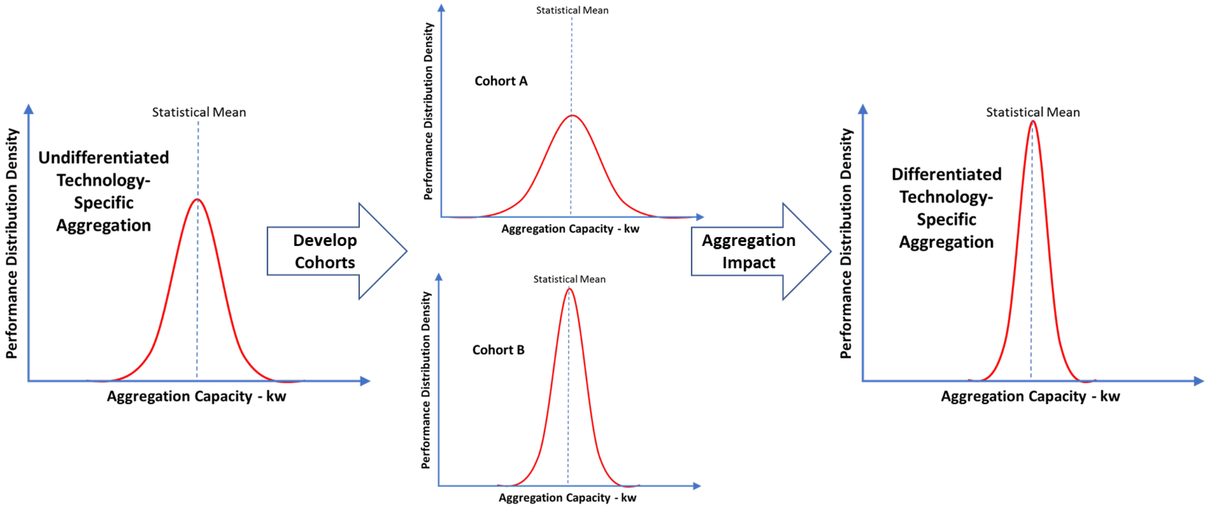

Figure 17. Illustration of Technology-Specific GER Aggregation Cohorting

Cohorting can improve technology-specific aggregation predictability by isolating distinct performance behaviors, narrowing performance distributions, and supporting stronger confidence-based accreditation values.

Cohorting is not required in every case. It is a practical way to improve predictability when a broad GER technology-specific aggregation contains customers or devices with meaningfully different performance characteristics. By isolating distinct performance behaviors, planners can assign higher accreditation values to more predictable sub-groups that would otherwise be effectively de-rated within a blended aggregation. Moreover, when multiple cohorts are

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[36] Minimum aggregation population size to hit a confidence target, scales approximately with Coefficient of Variation squared (CV^2), therefore, even a modest cohort-driven reduction in CV can materially improve accreditation and operating reliability. For further detail on Coefficient of Variation and impacts to GER aggregation analysis.

developed within an aggregation, those cohorts may also be used operationally during dispatch events. Practical outcomes of cohorting include:

- Tighter performance distributions as illustrated in Figure 17, which improves confidence-based accreditation.
- More reliable ramp and sustained delivery through cohort sequencing during a dispatch event.
- Clearer root-cause diagnosis when events underperform (cohort attribution instead of aggregation ambiguity).

Cohorting, when possible, improves comparability and reduces avoidable variability, but it does not eliminate uncertainty.

As a practical matter, the opportunity to develop more than one cohort at the feeder level or below is often limited by the relatively small number of technology-specific GER available at those locations. As a result, evaluating multiple technology-specific cohorts is more likely to be practical for grid needs defined at the substation level than for needs located deeper on the distribution system.

With aggregation structure established, the next step is to quantify uncertainty explicitly through probabilistic modeling and determine a dependable performance level for each technology-specific GER cohort or aggregation.

4.3 Probabilistic Modeling of GER Aggregations

Probabilistic modeling evaluates GER aggregation performance by translating real-world drivers of variability into a quantified range of outcomes rather than a single average expectation. Using the technology-specific performance representations established in Chapter 3 and the aggregation structures defined in Sections 4.1 and 4.2, this step produces distribution-level, risk-adjusted dependable aggregation capacity values suitable for planning purposes.

Probabilistic modeling is not a methodological preference - it is a planning necessity.

Probabilistic modeling begins by identifying the uncertain elements embedded in GER technology response curves and representing them as stochastic variables based on observed data, where available, or defensible engineering assumptions. For smart thermostats, this includes event shape, opt-out behavior, and post-event rebound. For batteries, it includes state-of-charge conditions, energy limitations, recharge impacts, and dispatch history. For EV charging flexibility, it includes plug-in coincidence, charging state, and customer behavior at the relevant hours. These are not abstract statistical constructs; they are the measurable sources of performance variability that determine whether an aggregation can meet a local grid need dependably. However, many utilities currently lack the granular, device-level behind-the-meter telemetry needed at the feeder or service-transformer level to characterize GER behavior with high confidence. Where sufficient historical data are unavailable, planners may need to rely initially on engineering assumptions, pilot results, or aggregated telemetry from third-party GER aggregators, with refinement over time as additional operating data become available. Improving performance visibility is therefore an important step in moving GER from conceptual potential to fully accredited, infrastructure-grade operational assets.

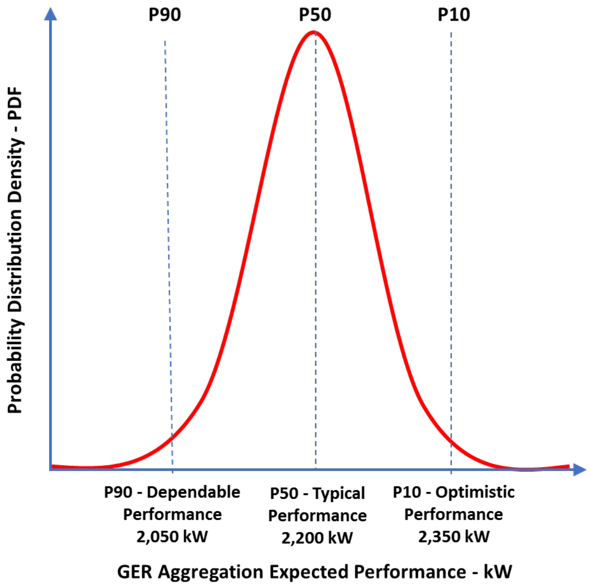


Figure 18. Percentile-based GER aggregation performance metrics.

Because GER performance is inherently stochastic, a probabilistic approach is required to support planning-phase evaluation of GER aggregation performance and design. The objective is not to predict performance perfectly, but to quantify the distribution of likely outcomes under the same conditions that drive the distribution constraint, such as weather, load, and operating state. This allows planners to select dependable capacity values that meet the grid need while explicitly managing downside risk.

Monte Carlo simulation can be used to generate time-resolved distributions of aggregate performance, such as hourly or event-interval outcomes, incorporating the variability drivers described earlier. The result is a set of performance distributions that quantify both central tendency and downside risk, rather than a single expected value.

For distribution planning, these distributions are summarized using percentile-based performance metrics that convert uncertain performance into dependable planning values, as illustrated in Figure 18. Percentiles provide a direct, transparent way to answer the key planning question: how much performance can be delivered, with high confidence, when it is needed?

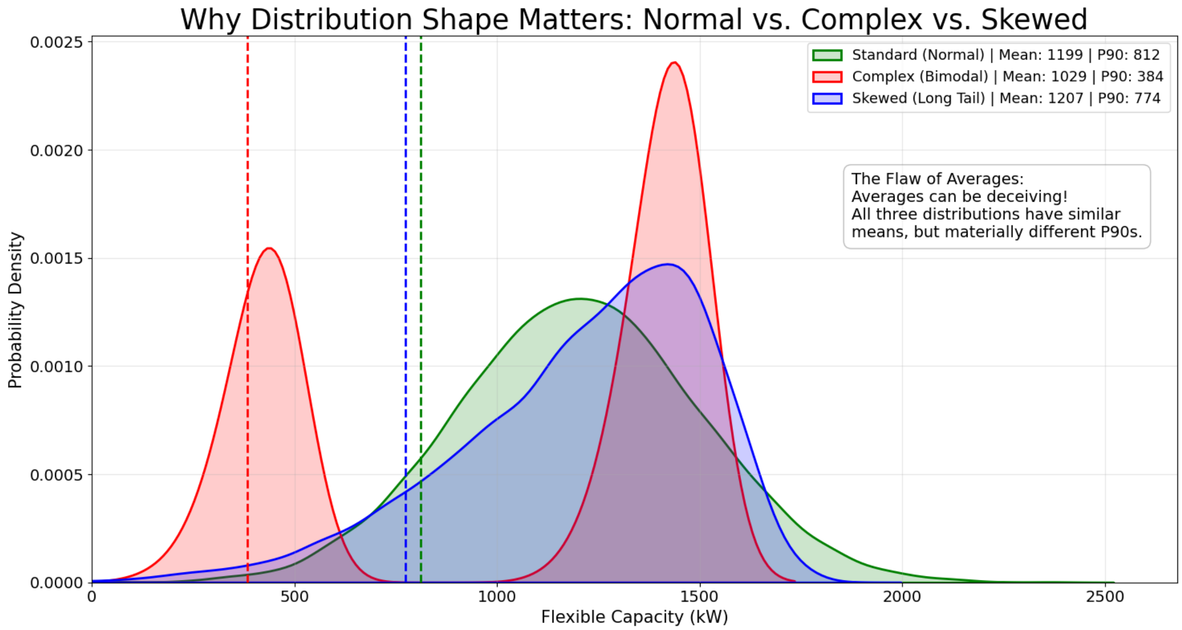
An exceedance percentile P(X) is the GER aggregation's performance that can be met or exceeded in (X)% of dispatch events. Exceedance percentiles translate performance uncertainty into planning values: P50 represents a typical (median) outcome, while P90 represents a conservative, dependable outcome the GER aggregation can be expected to meet or exceed 90% of the time.

Percentile framing also aligns with how distribution procurements and non-wires alternatives often express performance requirements in practice, emphasizing high availability thresholds and explicit headroom to manage non-performance risk. In the Xcel example discussed in Chapter 2, the performance requirement and embedded headroom imply a practical preference for exceedance-based capacity values rather than averages alone.

Because distribution constraints offer limited contingency options, and planners must compare GER solutions to traditional infrastructure ratings, conservative exceedance values (e.g., P90 or higher) are a reasonable metric to use. This converts probabilistic performance into a planning-grade capacity value that is dependable in the same way planners treat equipment ratings: not as the most likely outcome, but as a dependable value under stress conditions.

In probabilistic terms, those requirements imply an operational preference for exceedance-based capacity values rather than averages and an acknowledgement that there is residual risk even with an aggregation expected performance of P90. Probabilistic analysis can quantify the residual risk of non-performance and Distribution Planning Reserves can be appropriately sized and acquired. This is discussed in more detail in Chapter 5.0.

Figure 18 illustrates a performance probability distribution shown as a normal (bell-shaped) curve. Normal distributions are symmetric and are often summarized adequately by the mean and standard deviation, which provides a consistent, interpretable measure of dispersion. By contrast, GER aggregation outcomes are often non-normal; they may be skewed, heavy-tailed, truncated, or multi-modal, as illustrated in Figure 19. In those cases, the mean and standard deviation can still be computed, but '± standard deviation' bands can be misleading because they do not represent tail risk or asymmetry well. Percentile-based values (e.g., P90) remain valid because they are defined directly from the outcome distribution and make no assumption about distribution shape.


Why Distribution Shape Matters: Normal vs. Complex vs. Skewed

The Flaw of Averages:
Averages can be deceiving!
All three distributions have similar means, but materially different P90s.

Figure 19. Percentile-based analysis applied to non-normal performance distributions

Figure 19 also illustrates the percentile approach applied to a non-normal performance distribution. The planning logic is unchanged: select a conservative exceedance percentile that matches the reliability requirement (e.g., P90), regardless of whether the distribution is symmetric or skewed.

Once each technology-specific aggregation is expressed as a time-resolved performance distribution and accredited at a chosen exceedance level, the same framework can be applied to multi-technology portfolios, where diversification and correlation determine the dependable outcome, residual risk and requirements for the DPR.

4.4 Multi-Technology GER Aggregation Development

Distribution constraints may rarely be addressed with a single GER technology aggregation. Instead, multi-technology aggregations are likely needed to meet, or materially support, hourly capacity and event-duration requirements. Probabilistic analysis enables combining technology-specific, hour-by-hour performance distributions into a multi-technology aggregation performance distribution, allowing quantification of both expected contribution of each GER technology-specific aggregation and overall delivery shortfall risk.

The dependable capacity of a multi-technology aggregation must be modeled as a composite system, not calculated as the sum of its parts. Multi-technology aggregation performance exceedance values reflect joint probability outcomes of the technology-specific aggregations and are shaped by relative magnitudes, temporal characteristics, and correlations under shared conditions; thus, they must be evaluated using probabilistic analysis and modeling.

In Figure 20, four technology-specific GER aggregations are modeled as a multi-technology aggregation. The muti-technology aggregation's P90 (2005 kW) exceeds the grid need (1980 kW), indicating the aggregation is likely to meet or exceed the grid need in 90% of dispatches under the modeled conditions. Within this analysis, the number of individual GER devices can be modified, correlation characteristics can be varied, device-specific performance responses can be adjusted, and temporal sequencing can be modified to test various scenarios and examine sensitivities.

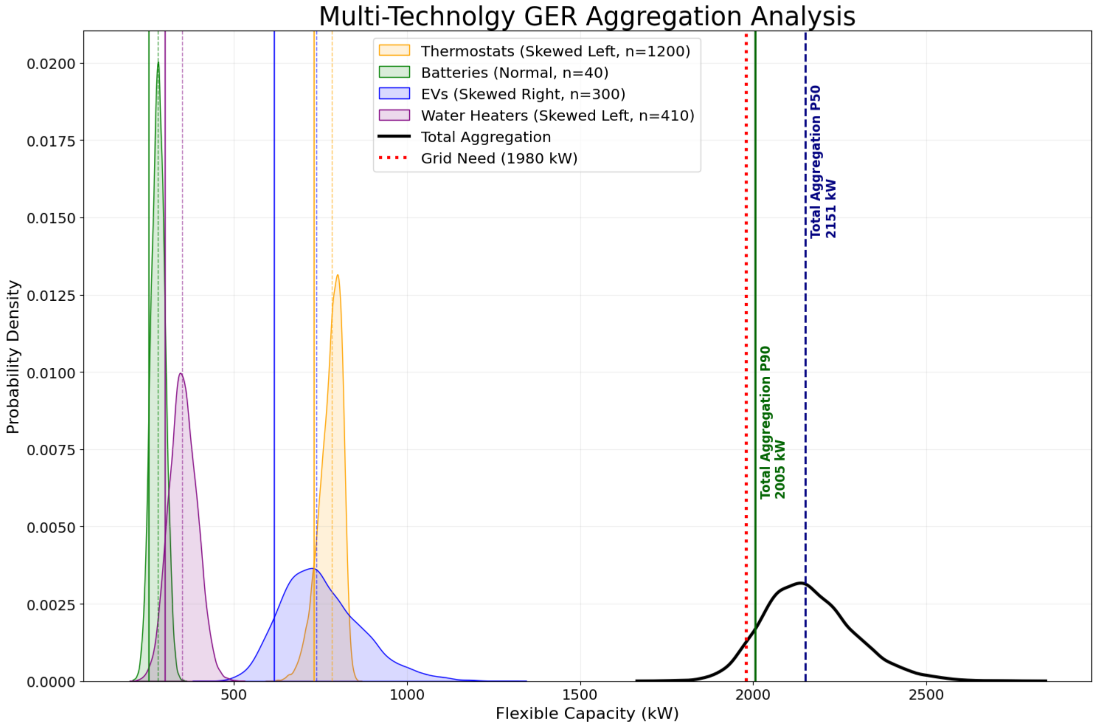


Figure 20. Illustration of probabilistic multi-technology GER aggregation analysis. *Probabilistic modeling of accredited technology-specific GER aggregations may be used to evaluate how the technologies perform when used together during a dispatch event.*

Probabilistic modeling of technology-specific GER cohorts or aggregations and their performance together evaluates the operational potential of a multi-technology GER aggregation. Figure 21 illustrates this concept. The analysis estimates each cohort's dependable capacity contribution on an hour-by-hour basis, reflecting its unique response characteristics and constraints. To deliver a dependable capacity reduction throughout the event, cohorts must be dispatched in a structured sequence. When GER technology-specific cohorts are optimally stacked to match the temporal constraint profile, the multi-technology aggregation's operational potential is demonstrated.

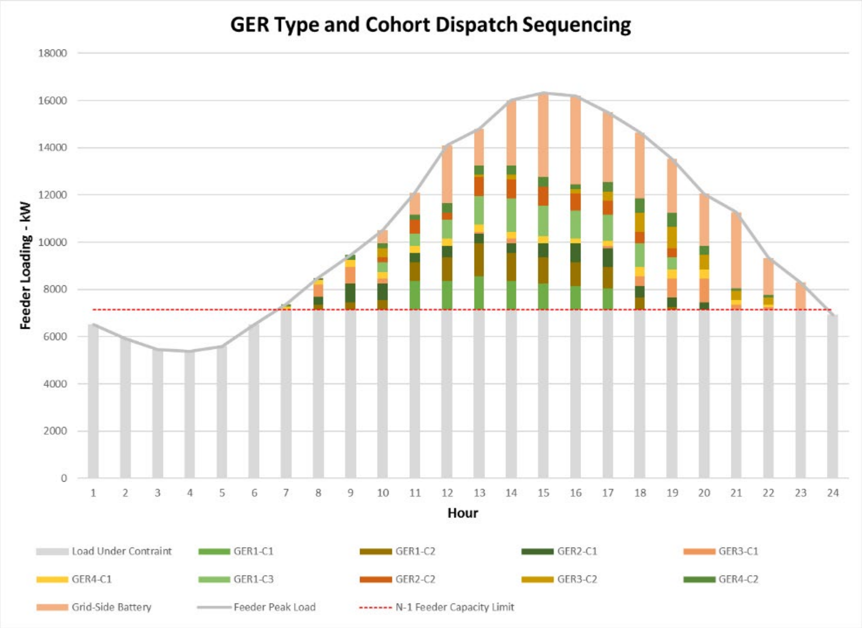


Figure 21. GER operational potential

Probabilistic modeling produces a range of expected aggregation performance, not a single number. Probabilistic modeling generates exceedance percentiles that characterize expected portfolio performance outcomes but there is still some residual performance uncertainty that must be considered. A practical way to summarize residual performance uncertainty is the gap between typical and dependable outcomes, such as the P50-P90 spread of aggregation's delivered capacity. A wider P50-P90 gap indicates greater uncertainty, while a narrower gap indicates increasing predictability. When this gap is large, additional diversification, contingencies, or an explicit DPR are needed to reach infrastructure-grade reliability; when it is small, performance is approaching deterministic behavior. Section 4.5 describes how this residual uncertainty translates into multi-technology aggregation design choices and a DPR.

4.5 Implications for GER Aggregation Design and Distribution Planning Reserves

Probabilistic analysis tells planners not only whether a GER aggregation can meet a grid need, but also how often it will do so under realistic operating conditions. However, percentile-based accreditation also reveals a second, equally important planning issue: even an aggregation sized to meet a grid need at P90 can still experience shortfalls, and distribution constraints often leave limited tolerance for them. This is the residual shortfall risk, but identifying its probability does not, by itself, specify the reserve quantity needed to manage it.

A practical way to represent this residual shortfall exposure is the P50–P90 gap. Used in this paper as a practical planning proxy, the P50–P90 gap represents the difference between a typical (median) outcome and a dependable planning outcome, and therefore the portion of expected capacity that cannot be relied upon during tail-risk events. By explicitly quantifying this uncertainty, probabilistic analysis provides the analytical basis for determining the amount of additional capacity or flexibility required to achieve the performance needed for distribution-level reliability.

An accredited GER aggregation may either fully meet a defined grid need or contribute dependable capacity as part of a portfolio of other accredited GER aggregations and/or complementary resources assembled to meet that grid need. In either case, the residual uncertainty of that GER aggregation should be explicitly addressed through DPR or equivalent reserve treatment. When multiple resources are combined to meet a grid need, the total reserve requirement may be informed by the reserve needs of the individual components, but should ultimately be confirmed based on the probabilistic behavior of the portfolio as a whole. The composition of such portfolios, including complementary solution types, is addressed further in Chapter 6.

For GER to serve as infrastructure, this residual uncertainty must be explicitly addressed through additional dependable capacity, flexibility, or other reserve treatment, as discussed further in Chapter 5.0.

4.6 Summary

This chapter showed how dependable accredited capacity values for GER aggregations are explicitly constructed through probabilistic analysis and how probabilistic modeling produces performance distributions for specified time periods (e.g., hourly) during a dispatch event. Exceedance percentiles translate those distributions into planning-relevant capacity values. In particular:

- P90 provides a defensible, dependable capacity value for aggregation planning under uncertainty.
- The P50–P90 gap provides a practical planning proxy for residual uncertainty; the portion of typical performance that is not dependable enough to rely on for infrastructure-level needs.

Chapter 4 established how technology-specific inputs are translated probabilistically into dependable capacity values and how residual uncertainty is visible through the resulting performance distributions. Chapter 5 addresses how that residual uncertainty is translated into an explicit Distribution Planning Reserve requirement and how that reserve may be supplied.

5.0 Distribution Planning Reserves

Chapter 3 established the first step of GER accreditation by defining technology-specific performance representations that describe how customer and device characteristics shape availability, capability, duration, event response, and variability. Chapter 4 then applied those inputs probabilistically to technology-specific cohorts and GER aggregations to derive dependable, risk-adjusted capacity values under a defined grid need. These analyses show not only the dependable performance that GER can be expected to deliver, but also the residual uncertainty that remains even after a conservative exceedance-based capacity value is selected.

When GER is used as a potential substitute for traditional distribution infrastructure, that residual uncertainty must be explicitly addressed rather than implicitly assumed away. DPR is the planning response to that remaining uncertainty. It provides the additional margin, or complementary mitigation, needed to ensure that a GER-based solution can satisfy distribution reliability requirements despite the possibility that delivered performance may fall short of the accredited dependable value under actual dispatch conditions.

Financial penalties for non-performance are often cited as the primary means of ensuring supplier performance, as done in wholesale transactions. For distribution constraints, that approach is insufficient for two reasons. First, at the granular level of distribution system constraints, the utility may have no backup option if a GER aggregator or orchestration platform fails to perform, whereas wholesale markets are supported by established reserve margins and alternative suppliers or resources. Second, often onerous financial penalties typically found in non-wires contracts have not prevented GER aggregators from abrogating contracts and may discourage some potential providers from offering distribution services at all (see Chapter 6.0). Accordingly, DPR is required to manage residual performance uncertainty in advance, while broader sourcing and orchestration considerations and risks are addressed through implementation planning.

This chapter explains how residual uncertainty identified through probabilistic analysis may be translated into DPR requirements and how those requirements may be satisfied through resource design and procurement. Section 5.1 addresses DPR sizing, while Section 5.2 discusses how DPR may be supplied or contractually maintained to support a dependable distribution solution.

5.1 Distribution Planning Reserve Sizing

When GER aggregations are used to defer or substitute for physical distribution infrastructure, the core question is not only how much dependable capacity they can provide, but also how much residual uncertainty remains around that capacity. Where a GER aggregation contributes to, rather than fully satisfies, a defined grid need, this aggregation-level uncertainty still must be explicitly recognized, even if the final solution is completed through a broader portfolio of accredited GER aggregations and/or complementary resources.

Accredited dependable capacity values do not eliminate uncertainty; they bound it at a selected confidence level. The purpose of DPR sizing is to determine how much additional margin or complementary mitigation is required so that a GER-based solution can satisfy the reliability requirement of a defined distribution grid need despite the remaining risk of under-performance.

Consistent with Chapter 4, the planning starting point is to apply probabilistic analysis to a GER aggregation in order to determine its dependable capacity value at a selected exceedance level, such as P90, under the conditions of a defined grid need. That dependable value is then compared to the grid need to determine whether the aggregation can fully meet the requirement, come close to meeting it, or contribute only part of the needed dependable capacity. Where the aggregation does not fully satisfy the grid need, additional resources, such as other GER aggregations, point solutions, or FTM GER, may be added to create a broader portfolio capable of meeting the need. In all cases, residual uncertainty remains around the accredited aggregation performance, and that uncertainty must be explicitly addressed through DPR or equivalent reserve treatment.

Selecting a dependable capacity value such as P90 does not eliminate uncertainty. P90 identifies a conservative planning value, but it does not by itself indicate whether aggregation performance is tightly clustered around that value or widely dispersed. That distinction matters because when the grid need lies at or near the selected dependable capacity value, the spread of outcomes around P90 affects the likelihood and consequence of under-delivery. DPR is therefore required to address the remaining variability that persists even after a conservative exceedance-based planning value has been selected.

To keep DPR sizing transparent and directly tied to the probabilistic outputs developed in Chapter 4, DPR (capacity) is defined here as the difference between the typical (median) outcome and the dependable planning point outcome:

- Distribution Planning Reserve (kW) = P50-P90

Using P50-P90 as DPR is reasonable because it represents the confidence derate between typical and dependable outcomes and scales with uncertainty: a wider P50–P90 gap implies a larger reserve requirement. P50 is not a planning target; it is a reference point for describing how much performance must be derated to achieve a dependable capacity value.

The P50-P90 convention is intended as a practical planning proxy rather than a universal sufficiency test.[37] Where the grid need has very limited tolerance for shortfall, where reliability targets are especially stringent, or where aggregation variability and correlation remain high, additional probabilistic testing may show that more reserve is required than the P50-P90 gap alone would suggest.

Figure 23 illustrates this reserve-sizing logic using an example in which the difference between the typical outcome and the dependable capacity value defines the residual uncertainty that must be covered through DPR. Referring to Figure 23, the aggregation's typical (median) outcome is 2,200 kW, while its dependable outcome is 2,050 kW. The 150 kW difference is not "the shortfall in the worst 10% of dispatches." Rather, it is the amount by which the aggregation's median performance must be derated when moving from a typical (median) outcome to a dependable planning value. Under this paper's design premise that the grid need is equal to or slightly less than the P90 capacity value, the 150 kW represents a DPR margin, in this example approximately 7.5% of the P90 planning value. That margin may be explicitly managed either through adding GER to the aggregation (expansion) or through developing separate reserve resources capable of covering the remaining uncertainty.

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[37] See Section 8, References, for a full listing of reference materials used to develop the P50-P90 gap used in this paper as a practical planning proxy

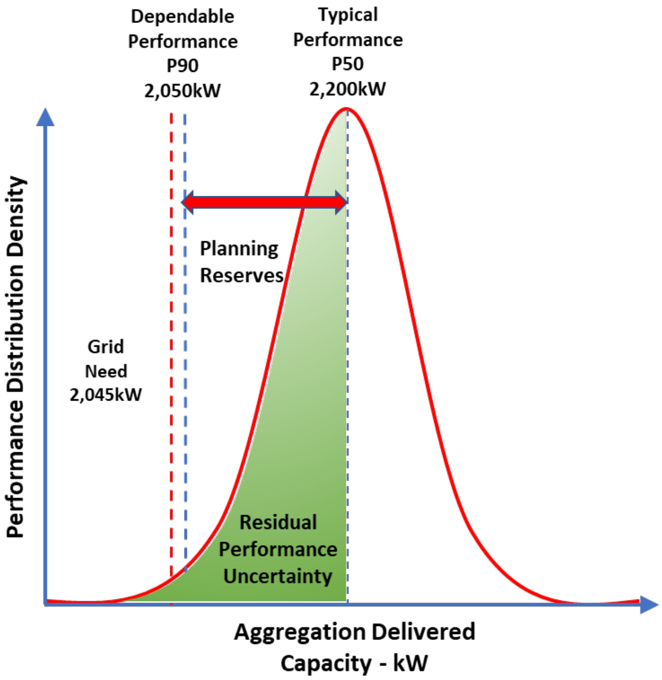

Figure 22. DPR addresses residual GER aggregation performance uncertainty.

An alternative way to size the DPR is to start with a required reliability target and use a probabilistic model to determine the additional capacity needed to meet it. For example, if a utility requires near-certain performance at a local constraint, the model can test whether the aggregation meets the grid need at that high confidence level (e.g., P(98)), and, if not, how much incremental resource is required. The model can also be used to evaluate how a reserve sized using the P50-P90 convention changes the probability of shortfall, for example, by showing how the grid-need threshold shifts from roughly P90 toward a higher exceedance level such as P95, as incremental resources are added. Importantly, the amount of reserve required depends on what is added: expanding the existing GER mix can increase aggregation capacity, but it may also increase variability and correlation, such that the last increment needed to achieve a very high confidence target can become disproportionately large and potentially much more expensive.

This creates an important economic tension in DPR sizing: higher confidence generally requires more reserve, and more reserve increases cost. As a result, the cost of achieving a higher-confidence GER solution may reduce, or in some cases eliminate, its economic advantage relative to a traditional infrastructure alternative. DPR therefore should not be sized in isolation from economics; reserve requirements should be evaluated together with incremental cost, reliability benefit, and the cost of competing non-GER and traditional solutions. The following section translates these sizing concepts into potential DPR design options and explains why the type of reserve resource often matters as much as the amount.

5.2 Distribution Planning Reserves - Resource Design and Procurement

Once the DPR has been defined for the GER aggregation, the next step is how that reserve will be supplied in a way that is both dependable and cost-effective. The uncertainty characteristics of the reserve resource matter. Adding more of the same highly variable resources (if they are even available on the feeder or substation level) can increase both capacity and variability, while adding a more controllable and predictable resource can provide a tighter and more dependable margin. This section describes potential options to consider for constructing the DPR and the tradeoffs between them.

Option 1: Expand the existing GER aggregation
One approach is to meet the reserve requirement by adding incremental resources that match the existing technology mix and operating rules. This may be attractive when additional GER capacity is readily available and acquisition is cost effective. At the distribution level, however, this option may be constrained by the limited amount of additional technology-specific GER that is both electrically relevant to the local grid need and realistically available for enrollment or dispatch. However, because the added resources may share similar drivers of uncertainty, such as weather correlation, customer behavior, device availability and orchestration risks, aggregation expansion may also increase both total capacity and the spread of outcomes. As a result, nominal capacity may increase faster than dependable capacity, and more incremental resources may be required than might be expected to materially improve high-confidence performance or reduce the probability of shortfall. In probabilistic terms, nominal capacity may increase faster than the selected dependable capacity value if the added resources do not materially reduce correlation during critical hours. Like-for-like expansion may therefore be most effective when the added resources also diversify the aggregation, for example through different customer segments, locations within the constrained distribution area, orchestration strategies, or technologies that reduce correlation during critical hours. Large additions of GER may also require more granular cohorting, dispatch targeting, and orchestration complexity, increasing implementation cost.

Option 2: Incremental complementary resource (“firming reserve”).
A second approach is to meet the reserve requirement with a resource that has more predictable and controllable performance during dispatch hours, such as a FTM battery. This option may be particularly important where the constrained feeder or substation has insufficient additional GER available to expand the original aggregation to the level required for dependable reserve coverage. In this structure, the GER aggregation provides the bulk of the capacity benefit, while the complementary FTM battery serves as a firming resource that provides a dependable margin that reduces tail risk in the probabilistic outcome distribution. When these resources are not customer-owned, operated only under utility direction, are not subject to customer preference or behavior, and operational performance is less variable, a smaller quantity of firming reserve may achieve the same reliability improvement that would otherwise require a larger amount of “like-for-like” GER expansion. In probabilistic terms, a firming resource may improve high-confidence percentile outcomes more efficiently by tightening the lower tail of the distribution rather than simply increasing expected capacity.

Option 3: Hybrid reserve strategies (GER aggregation + firming + operational measures).
In many cases, the lowest-cost and most robust solution may be a hybrid: moderate aggregation expansion combined with a smaller amount of firming reserve and defined operational measures. This approach recognizes that reserve design is not solely a capacity

question, but also a question of how different resources perform across the dispatch window and how those performance characteristics interact probabilistically. A hybrid strategy is often most practical where some additional local GER is available, but not enough to fully satisfy the reserve requirement without relying on a more dependable complementary resource or operational measure. Distribution capacity constraints are driven by conservative N-1 thermal ratings established using extreme weather assumptions and a worst-hour analysis. In practice, however, the thermal risk during a constraint event is often not flat across the event window; potential violations may occur in only one or two hours as ambient temperature and loading conditions peak. If methods are available to validate thermal capability by hour, such as time-varying cable thermal limits based on monitored conditions and operating procedures, the grid need can be treated as a time-varying shaped threshold rather than a single constant value. This allows the GER aggregation, and any complementary reserve resource, to be sized and dispatched to meet the hourly grid need, reducing unnecessary reserve procurement while maintaining reliability. In probabilistic terms, a hybrid strategy can improve percentile outcomes not only by adding capacity, but also by reshaping the timing and controllability of that capacity so that reserve is concentrated where shortfall risk is greatest.

These options may be evaluated using the same probabilistic framework described in Chapter 4.0 by rerunning the model with candidate reserve designs and comparing at least three outputs: (1) the dependable capacity at the required confidence level, (2) the probability of shortfall relative to the grid need, and (3) the incremental cost and operational complexity of achieving the desired reliability improvement. This enables planners to test whether a proposed reserve design merely increases “average” capability or meaningfully improves high-confidence performance. This makes clear that DPR sizing and procurement is a joint exercise: the amount of reserve required depends on what is added, how it performs during critical hours, and how it interacts with the uncertainty characteristics of the underlying GER aggregation.

5.3 Summary

Chapter 5 translated the probabilistic accreditation results developed in Chapters 3 and 4 into an explicit planning reserve requirement for GER-based distribution solutions. Section 5.0 defined DPR as the planning response to the residual uncertainty that remains even after a dependable, exceedance percentile-based capacity value has been established. Section 5.1 showed how DPR may be sized using the probabilistic outputs of the accreditation framework, including the use of the P50-P90 gap as a practical planning proxy for residual uncertainty. Section 5.2 then showed that the design and procurement of DPR must be evaluated in terms of how different reserve options affect dependable capacity, shortfall risk, cost, and implementation complexity.

Within the broader techno-econometric framework, DPR bridges probabilistic performance modeling and actionable procurement and planning decisions. Reserve requirements directly influence:

- Required GER solution size and composition
- Procurement and sourcing strategies
- Incremental cost to ratepayers
- Selection between aggregated, point, or hybrid solutions

GER aggregations and broader GER-based solutions cannot be evaluated using deterministic capacity assumptions without exposing utilities to unacceptable operational and reliability risk at constrained distribution locations. Conventional distribution planning embeds margin through equipment ratings, contingency criteria, and conservative assumptions. By contrast, the DPR construct makes that margin explicit by specifying how much additional dependable capacity, or complementary mitigation is required to prevent violations. Percentile-based reserve estimates for GER aggregations align with traditional distribution planning principles by making the reliability margin explicit and defensible.

By defining reserves using empirical aggregation or solution performance distributions, utilities gain transparency into the tradeoff between cost, risk tolerance, and reliability, enabling consistent comparison between GER-based solutions and traditional infrastructure options. Together with the accreditation framework developed in Chapters 3.0 and 4.0, the DPR construct enables utilities to determine not only whether a GER-based solution can contribute dependable capacity, but also what additional reserve margin is required and how that margin may be most effectively provided.

While DPR addresses the performance uncertainty revealed through probabilistic analysis, delivered performance also depends on real-world implementation factors such as customer participation stability, supplier and platform concentration, sourcing structure, and orchestration design. These issues should be considered alongside the probabilistic results, but they are best addressed outside the accreditation and reserve-sizing framework itself. Chapter 6 addresses how accredited dependable performance and the required reserve margin are translated into practical implementation choices.

6.0 GER Solution Implementation Planning

Effective solution portfolio development translates technical operational potential into operational reality. This step in the overall process builds upon the GER accreditation and planning reserve analyses. The prior steps involving grid needs analysis and probabilistic analysis establish the "what" in terms of accredited GER dependable performance and required Distribution Planning Reserve. The next step involves "how" to assemble, source, and operationalize that GER flexibility to reliably and cost-effectively address the need. This requires aligning three dimensions:

- Match Solutions to Grid Need: identifying the GER technology(ies) to use in a specific solution class alone or in a portfolio based on the probabilistic analyses
- Selecting Sourcing Method(s): rates/pricing, utility programs, and/or procurements
- Orchestration Design: how to animate the flexibility, at what granularity, and through which operational architecture (e.g., controls, autonomous, and/or customer consumption change)

The objective is to achieve a practical, Pareto-optimal solution in which incremental complexity and cost are justified by incremental distribution value for all ratepayers.

6.1 Match Solution(s) to Grid Need

Effective distribution planning and the use of GER solutions hinge on selecting the solution or combination of solutions that match the requirements of a specific grid need. Misalignment between the need and the solution type increases costs, operational complexity, and reliability risk. Three general classes of GER solutions are typically employed individually or as part of an overall portfolio to address distribution-level needs.

Customer GER aggregation is designed to operate as a single grid asset. Aggregations of customer BTM GER are most effective when the required flexibility in magnitude, duration, and probabilistic performance can wholly or substantially meet the grid need. Because customer adoption patterns and device performance vary widely, as discussed, aggregations must be large enough to support probabilistic assessment of adequate performance. An aggregation may need to incorporate multiple cohorts to manage heterogeneity, reduce uncertainty, and achieve dependable aggregate performance. Also, more than one GER technology may need to be aggregated to provide complementary performance characteristics to address the required performance.

Aggregation requires sophisticated orchestration platforms, customer recruitment, and real-time operations across multiple technology layers, often involving several organizations and hundreds or thousands of devices. This creates multiple performance dependencies beyond the GER technologies themselves. The orchestration performance considerations are discussed below. For these reasons, GER aggregations have been most effective at the subtransmission, substation level, and on selected feeders with sufficient available GER to achieve the required performance.[38]

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[38] Based on a review of utility distribution NWA evaluations and interviews with utilities and aggregators. See, D. Murdock and R. Yu,

Utility-controlled FTM GER, such as distributed generation and battery storage deployed specifically for distribution grid needs, offers more deterministic, controllable performance because these resources are designed specifically for grid use. This contrasts with customer GER, which are designed primarily for the customer's use and only secondarily for possible grid use. This inherently creates a more predictable resource, akin to similar generation and battery technology in the bulk power system. Several U.S. utilities, including those in Maryland[39] and Massachusetts[40], already use FTM batteries to address local constraints. While these assets provide greater operational certainty, they are typically more expensive than customer-based solutions and may be oversized for narrowly defined needs or insufficient for longer-duration constraints if sized to fit typical distribution budgets. Batteries also impose cycling limits and asset wear that must be actively managed. When customer GER and point solutions cannot meet the required quantity, duration, or reliability, FTM resources can provide essential capability as part of a broader portfolio, including, for example serving as a firming resource that supplies DPR for a customer-based GER aggregation.

GER point solutions address grid issues affecting a single customer or a small, well-defined group. Examples include modifying EV charging behavior to relieve a service transformer or adjusting inverter settings to manage voltage on a lateral. Because these problems have identifiable causes, they can often be resolved directly through targeted rate designs, control settings, or flexible connection agreements. In such cases, a point solution may be more effective and less costly than aggregating other customers' resources, which may add unnecessary complexity without resolving the root cause. For example, voltage variation caused by solar PV may be addressed by adopting inverter standards, such as IEEE 1547-2018, as a requirement for interconnection. Likewise, requiring an EV time-of-use (EV-TOU) rate may provide sufficient economic incentive to change a customer's EV charging pattern and thereby relieve an otherwise overloaded service transformer serving that premise.

The table below summarizes each of the solution classes and their applicability considerations.

Table 2. GER Solution Classes[41]

FTM Battery / Distributed Generation (DG)	Customer GER Aggregation	Point Solutions
• Utility-contracted or owned; dispatched directly with GER operator	• Coordinates many customer devices to act as a single grid resource	• Address a hyper-local grid issues created by one GER or a small well-defined group
• BESS/DG asset is designed to meet larger distribution needs at a substransmission or substation level, and potential residual bulk power uses	• Best when the location or needed grid capacity exceeds what any one device can provide and sufficient GER are available	• Examples: modifying an EV charging schedule to relieve a service transformer; adjusting inverter settings to manage voltage on a lateral
• More deterministic, controllable performance – but may be more expensive per kW	• Greater variability than utility-controlled assets – probabilistic accreditation is essential	• A cost-effective approach when the problem has an identifiable single cause
• Competitive procurement methods using NWA performance contracts work well	• Competitive NWA procurements haven't been very effective – programmatic approaches show promise	• Simpler to implement – targeted time of use rates, inverter control settings, or flexible connection agreements

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[39] Eversource, Utility-scale Battery Storage Demonstrations
[40] Maryland Public Service Commission, Energy Storage Pilot Program Interim Report, 2024
[41] P. De Martini, DOE Innovator Fellow presentation, April 21, 2026

6.2 Select Sourcing Method

6.2.1 Sourcing Method Costs

When examining GER solutions as stand-alone solutions or within a portfolio, it is necessary to compare the resulting incremental cost to the traditional “wires” alternative, as is required in most distribution non-wires alternative regulations. However, when developing a portfolio of potential solutions, it is also important to examine the incremental cost impacts of each GER type, orchestration mechanism, and sourcing method on ratepayers. This is because different solutions and sourcing methods have different incremental ratepayer costs.

Traditional grid assets usually provide the greatest operational certainty, but they may also have the highest incremental cost. Customer time-of-use (TOU) rates, redirected demand side management (DSM) programs, and aggregated customer GER using existing customer-sited GER may lower ratepayer costs but entail performance risks. Portfolios can balance these trade-offs to be cost-effective while ensuring reliability. However, if GER solution portfolios cannot reliably meet distribution needs, utilities might need to pursue traditional investments. Clearly understanding these incremental impacts is essential when developing solutions and portfolios for distribution grid needs.

For example, implementing an EV-specific TOU rate incurs minimal extra expense. Similarly, reallocating existing DSM budgets to fund geo-targeted initiatives may be possible without increasing ratepayers' costs. Conversely, acquiring aggregated customer GER services through NWA solicitations or tariffs based on the value of deferred or avoided distribution investments usually results in incremental costs for ratepayers. This is summarized in Table 3. Incremental ratepayer cost of GER sourcing methods.[42]

Table 3. Incremental ratepayer cost of GER sourcing methods.

Sourcing Method	Incremental Ratepayer Cost
Tariffs/Price Signal (VDER, TOU)	Relatively low cost for billing changes and customer communications
DSM/New GER Programs (Geo-targeted)	None, if the existing authorized program funding is redirected to geo-targeted/temporal needs
BYOD Program (Geo-targeted)	Cost to implement the program and compensation set at the deferred/avoided value
Distribution NWA Procurement/Bilateral Contract	Cost is based on competitive proposals but typically capped at the deferred/avoided value
Distribution Flexibility Market Services	Market implementation cost + cost of purchased flexibility service at market prices

6.2.2 Service Provider Considerations

GER solutions are ultimately only as reliable as the entities delivering them. For example, independent aggregators face structural challenges in distribution markets driven by multiple factors. Distribution investment deferral opportunities often total only tens or hundreds of

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[42] P. De Martini, S. Succar, and P. Cook, Sourcing Distributed Energy Resources for Distribution Grid Services, DOE-Office of Electricity, 2024.

thousands of dollars over multiple years.[43] Customer acquisition, telemetry, and engagement costs frequently exceed service revenues. Performance-based contracts may impact revenue recognition and expose firms to penalties and liquidated damages.

Between 2020 and 2025, many residential aggregators exited the market or were forced to pivot their business model (e.g., Swell, Enbala, Sunverge). The residential and small commercial markets are consolidating toward manufacturer-aggregators whose business models combine product sales with grid services (e.g., Tesla, Google/Nest, ChargeScape). This has coincided with increasing GER technology-specific concentration.

The result of this evolution is fewer independent GER manufacturers/aggregators, each having material market concentration in specific GER technologies. For example, the smart thermostat market has four major vendors accounting for over seventy percent of all installed devices in the US, based on Parks Associates' 2025 analysis (Figure 23).[44]

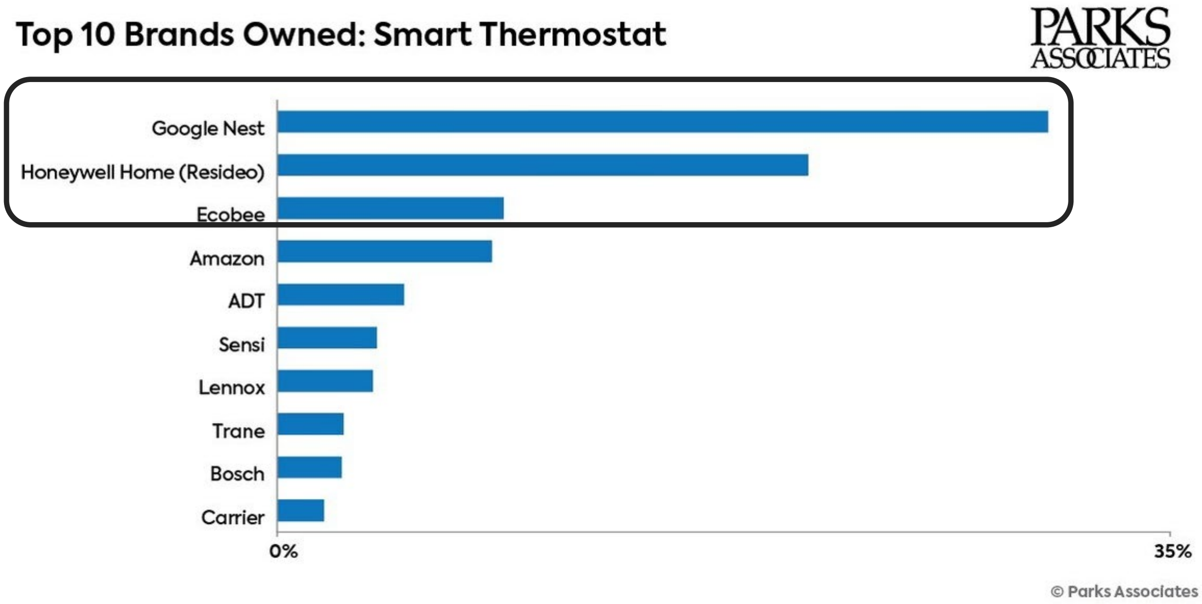

Figure 23. 2025 US smart thermostat market share (source: Parks Associates).

The residential battery and EV markets are similarly concentrated among a small leading group, led by Tesla, according to reports.[45,46] This means that for certain distribution substations, feeders, or laterals, one manufacturer's battery system may be dominant. The limited diversity of GER technologies and providers reduces redundancy, increases vulnerability to manufacturer-specific technology failures and supplier business strategy changes, and limits utilities' ability to build resilient portfolios.

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[43] To-date utility confidence in non-wires alternatives using customer GER has not reached a level where distribution investment avoidance is considered viable. The methodological approach described in this paper is intended to address this confidence gap.

[44] Parks Associates, Smart Thermostat Market Assessment 2025

[45] Wood Mackenzie, *"Which installers and battery vendors top the US distributed solar-plus-storage leaderboard?"*, 2023

[46] EnergySage, Marketplace share in the second half of 2024, May 2025

6.3 Design Orchestration Architecture

Solution and sourcing choices shape the orchestration architecture. There are multiple permutations among the three classes of GER orchestration: controls, autonomous, and customer behavioral.[47] These mechanisms may be used to orchestrate GER to provide distribution grid services from aggregated GER, FTM generation or battery storage, or customer point solutions. The ratepayer cost advantage of each solution must be balanced against other operational risks, and the net value that a GER provides may diminish as operational complexity increases. For example, striving to control more individual GER to address low-level distribution grid issues can increase complexity and implementation costs, thereby diminishing marginal benefits to ratepayers. These challenges become most acute for highly localized distribution needs that demand sustained, multi-hour performance. As such, even with advanced probabilistic analyses and cohorts employing diverse technologies, distribution-level aggregations generally exhibit greater variability in availability and dispatch accuracy than utility-controlled assets, such as FTM batteries.

Additionally, each mechanism entails specific costs and complexities for implementation, operation, and coordination across the selected types of GERs. This may include the following aspects depending on the architecture:

- Telemetry and controls at the feeder, feeder section, or service transformer levels
- Operational information and control coordination across utilities, aggregators, device vendors, and customers
- Interoperability constraints, information and operational technology reliability, and cybersecurity

The best solutions will be found in reducing unnecessary complexities and associated costs. This is highlighted in the trade-off between increasing orchestration complexity and incremental ratepayer net benefits (Figure 24).

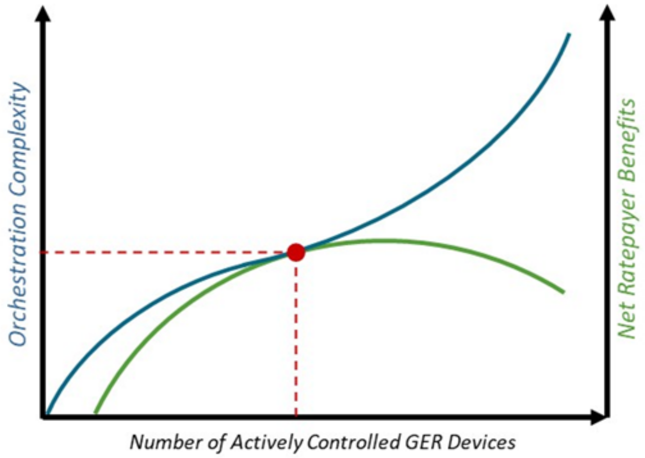

Figure 24. Distribution-level relationship between GER orchestration complexity and net ratepayer benefits.

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[47] S. Vaidya, S. Patel, and P. De Martini, Distribution Grid Orchestration, 2025

This conceptual graphic illustrates the relationship between the number of actively controlled GERs and two competing factors: orchestration complexity (blue curve) and net ratepayer benefits (green curve). For example, as more individual GER devices are used to address increasingly granular distribution needs within an actively controlled portfolio, both costs and complexity increase, while the additional value provided to ratepayers eventually decreases. The red point indicates an approximate Pareto-optimum point where the marginal cost and benefit curves intersect, suggesting a practical upper limit for efficient GER orchestration.

This relationship underscores a key principle for effective distribution-level GER integration: solutions, sourcing, and orchestration strategies must reliably deliver net-positive benefits to all ratepayers. Achieving this requires a deeper industry understanding of the trade-offs among control granularity, operational complexity, incremental value, and distribution-level risk exposure. As distribution systems evolve, optimizing these trade-offs will be crucial for ensuring that GER-based solutions remain both operationally feasible and economically advantageous.

There is rarely a single optimal solution; instead, well-designed portfolios align multiple approaches to deliver reliable performance at the lowest cost.

A portfolio approach employs customized solutions based on specific GER technologies, developed through a specific solution type, sourcing method, and orchestration mechanism, given the expected performance. Additionally, if more than one GER technology aggregation or solution type is needed, it is necessary to consider a solution "stack" described in Chapter 5 that optimizes the performance, costs, and risk mitigation in a manner analogous to bulk system resource stacks as developed in integrated resource planning.

For example, a grid need may require specific point solutions (no incremental ratepayer cost), aggregated customer GER built from existing customer resources (partial incremental ratepayer cost), and FTM-distributed resources (full incremental ratepayer cost) to meet performance requirements. Such a combination can also reduce operational risks and improve cost-effectiveness. In another example, an FTM battery can serve as a portfolio anchor or reserve backstop, preserving performance if and when customer resources underdeliver in real time. In this FTM battery example, targeted customer actions can reduce the size and cycling requirements of that battery. Table 4 illustrates potential solution types for certain distribution grid needs at different levels in a system.

Table 4. Illustrative Grid Need and Potential Solution Combination Examples[48]

Grid Need Type	Scale / Location	Example Solutions
Substation Capacity	Sub-transmission / Substation	GER Program / BTM Customer VPP / FTM Battery
Feeder Capacity	Primary Feeder	BTM Customer VPP / FTM Battery
Feeder Segment Overload	Feeder Segment	FTM Battery / Flexible Connections / BTM Customer VPP /
Lateral / Transformer Overload	Lateral / Secondary	TOU-EV Rate / Flexible Connections
Voltage Violation	Feeder Segment / Lateral	Smart Inverter Standards / Volt-Var Service Tariff
EV Charging Constraint	Feeder Lateral / Secondary	TOU-EV Rate / Managed Charging

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[48] P. De Martini, DOE Innovator Fellows Presentation, April 21, 2026

6.4 Summary

Effective GER solution deployment at the distribution level recognizes that each solution class, including aggregated GER, FTM GER, and customer point solutions, carries distinct cost structures, operational risks, and performance limits. Additionally, as orchestration becomes more complex, implementation costs and operational risks tend to rise while marginal ratepayer benefits diminish. The practical objective, therefore, is not maximum controllability, but a Pareto-optimal design in which incremental value justifies incremental complexity and cost.

These findings underscore a central theme of this paper: realizing GER value for distribution needs requires disciplined planning frameworks, probabilistic performance analysis, and solution portfolios that prioritize net benefits for all ratepayers. The concluding chapter synthesizes these insights into actionable principles for regulators and utilities as distribution systems evolve toward more dynamic, resource-diverse architectures.

7.0 Conclusion

Growing building, transportation, and industrial loads, and the adoption of GER technologies, are reshaping distribution system operations and business models for U.S. electric utilities. Grid-edge resources offer a meaningful opportunity to manage these pressures in ways that can complement or, in specific cases, substitute for traditional infrastructure. This includes the pressures GER creates when unmanaged. Realizing this opportunity requires moving beyond conceptual promise: GER must be planned, accredited, and operated with confidence comparable to that of physical assets, and the analytical methods to do so must be grounded in the realities of distribution system behavior.

Distribution systems operate under fundamentally different conditions than bulk power systems. Distribution constraints are hyper-localized, customer populations are relatively small, and contingency options are limited. As a result, the statistical smoothing that supports large-scale aggregation of GER at the transmission level does not reliably apply at the feeder, lateral, or service-transformer level. Small customer GER performance must therefore be evaluated probabilistically, using technology-specific characteristics, aggregation behavior, and correlation drivers to produce dependable, exceedance percentile-based capacity values. Percentile-based accreditation provides a transparent bridge between inherently variable distributed resources and the deterministic standards that underpin distribution planning. This can give distribution planners and operators greater certainty about the dependable capacity available to address a grid need. This also establishes a principled basis for the distribution planning reserve required to manage residual uncertainty, enabling GER to defer or avoid the construction of physical assets while maintaining distribution reliability.

The analytical approach described in this paper does not constitute a fully prescribed methodology ready for immediate adoption. Rather, it establishes a common technical language and a set of principles regarding probabilistic accreditation, portfolio-based solution design, and explicit planning reserves. Regulators, utilities, and aggregators can apply and adapt these elements within their respective contexts (Table 5). The value of these principles lies as much in the decisions they enable as in the calculations they support.

Table 5. Considerations for GER Utilization for Distribution Needs[49]

Regulators	Utilities	DER Aggregators
Adopt probabilistic GER accreditation methods and DPR for distribution-level proceedings, including DSP	Integrate probabilistic GER operation potential analysis into distribution planning processes	Provide technology-specific performance data to support GER accreditation
Design performance requirements for GER tariffs, programs, and procurements that balance risks between utilities, customers, and third parties	Design sourcing portfolios (rates, programs, and procurements) matched to each constrained area	Engage utility planning cycles to align dispatch capabilities with identified grid needs
Consider Value of GER/VPP tariffs and GER programs with distribution locational and temporal differentiation	Implement flexible interconnection and service connections as customer options	Adopt an industry-standard customer code of conduct

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[49] P. De Martini, DOE Innovator Fellow presentation, April 21, 2026

Establish performance reporting requirements to validate accredited GER capacity values over time	Track GER performance to update accreditation and reserve values as empirical data accumulates	Adopt standard interfaces to reduce complexity risks and costs of GER services

For utility regulators, the most consequential near-term decisions involve embedding these principles into proceeding structures before GER deployments scale further. This means designing performance requirements for GER tariffs, programs, and procurements that explicitly allocate risk among utilities, customers, and third parties rather than leaving performance obligations ambiguous and defaulting to penalties after the fact. It also means establishing performance reporting requirements that allow accredited capacity values and the DPR to be updated as empirical data accumulates, creating a feedback loop between field experience and regulatory standards. Regulators can further strengthen distribution system planning proceedings by requiring that GER value analyses incorporate locational and temporal differentiation, ensuring that tariff and program incentives reflect where and when GER capacity actually has grid value.

For utilities, the framework reframes several planning and procurement decisions that are currently made on ad hoc or pilot-scale terms. Integrating probabilistic GER operational potential analysis into distribution planning processes allows capacity needs and GER suitability to be assessed together rather than sequentially, enabling earlier identification of constrained areas where GER portfolios are technically viable. From there, utilities can design sourcing portfolios (i.e., combining rates, programs, and targeted procurements) that are matched to the specific load and constraint profiles of each area, rather than applying uniform program structures across diverse feeder conditions. Flexible interconnection and service connection options can further expand the pool of eligible GER by reducing the barriers customers face in participating. And tracking actual GER performance over time allows utilities to move accreditation from ex ante assumptions toward empirically grounded values, progressively reducing the conservatism embedded in the DPR as confidence grows.

For GER aggregators and manufacturers, the framework clarifies what infrastructure-grade participation actually requires and points to specific business and operational decisions that follow from that clarity. Providing technology-specific performance data to support GER accreditation is not merely a regulatory compliance exercise; it is the mechanism by which aggregators can demonstrate the dependable capacity of their portfolios and compete on equivalent terms with wires alternatives. Engaging directly with utility planning cycles, rather than responding only to open solicitations, allows aggregators to align dispatch capabilities with identified grid needs before procurement windows close. Adopting industry-standard customer codes of conduct and standard technical interfaces reduces the complexity and transaction costs that currently limit GER participation at distribution scale, and positions aggregators to operate across multiple utility territories without bespoke integration for each.

Across all three groups, a common enabler is the explicit treatment of uncertainty. GER can play a material role in managing distribution costs and complexity, but only when performance variability is quantified, allocated, and managed rather than assumed away. The methods described here do not advocate for any particular technology, sourcing method, or market structure. Instead, the techno-econometric framework referenced in this paper offers a neutral, analytically grounded basis for evaluating when, where, and how GER can be used with confidence and for making the regulatory, planning, and commercial decisions that follow from that evaluation.

As distribution systems continue to evolve, the question is no longer whether GER can address grid needs, but under what conditions they can be relied upon. By applying probabilistic analysis to determine Operational Potential and by designing cost-effective portfolios of GER solutions, regulators, utilities, and aggregators can move from today’s limited use of GER toward broader operational adoption, helping ensure that distribution grids remain reliable and affordable.

Appendix A – Distribution GER Techno-econometric Model

The distribution GER service techno-econometric model (Figure A-1) provides a disciplined, end-to-end framework for translating grid-edge resources (GER) from promising concepts into infrastructure-grade distribution solutions. It integrates distribution grid needs, technology-specific GER performance, customer behavior, probabilistic modeling, and economic tradeoffs into a single planning workflow. Rather than assuming flexible resources will perform as expected, the model treats GER as inherently variable and quantifies that uncertainty, converting stochastic device behavior into accredited, dependable capacity values through probabilistic analysis. It then explicitly identifies residual risk and planning reserves before turning to solution design, sourcing methods, and orchestration architecture. By linking engineering feasibility with operational reliability and ratepayer economics, the techno-econometric process enables utilities and regulators to evaluate GER portfolios on the same footing as traditional infrastructure, ensuring that non-wires solutions are not only innovative but also demonstrably reliable and cost-effective.

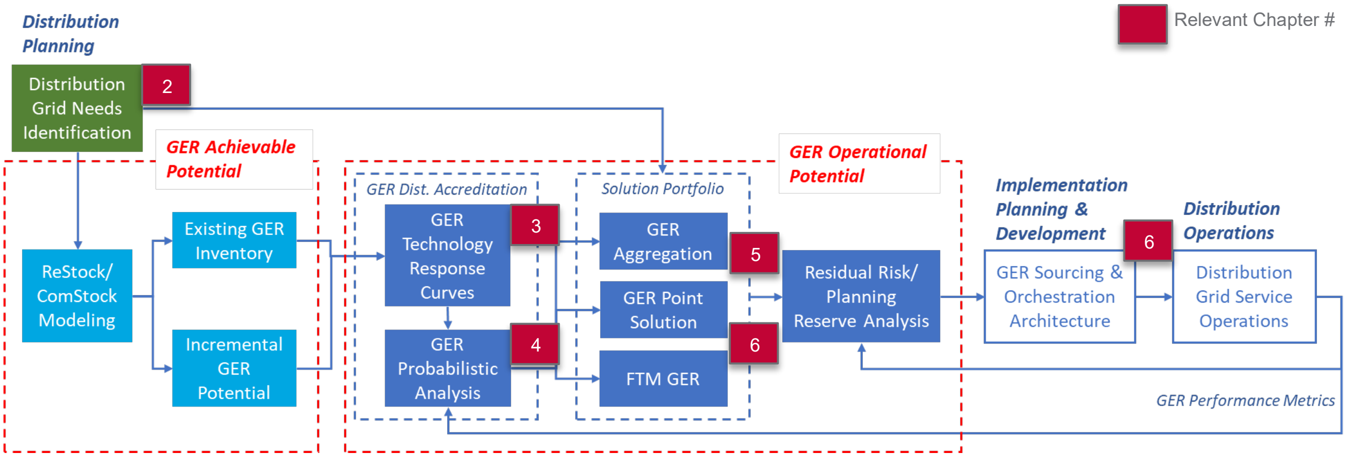

Figure A-1. Distribution GER services techno-econometric model.

The model comprises five core elements:

A.1 Distribution Grid Needs Identification

Identification of specific distribution grid needs is a key step in a utility's Distribution Planning Process. This involves identifying the specific distribution grid constraints and related engineering requirements to be addressed by potential GER solutions. Utility grid needs assessments produce this information, and several states require utilities to publish this information[50]. This includes parameters such as temporal power flow-thermal capacity limits (i.e., ampacity), voltage limits, and protection relay criteria.

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[50] San Diego Gas & Electric, Grid Needs Assessment, 2023. https://www.sdge.com/sites/default/files/regulatory/R21-06-017%20SDGE%202023%20IPE%20DPAG%20Report.pdf

A.2 Small Customer GER Achievable Potential

DER achievable potential represents the portion of technical or market potential for customer grid edge resources that are realistically available to be influenced through rates, programs, or procurements. It reflects practical constraints such as customer eligibility, technology adoption rates, participation behavior, housing and building stock characteristics, and regulatory or program design limits. Achievable potential is used to size and shape DER programs by estimating how much flexible load, generation, or storage could plausibly be enrolled under specific offerings within a given geography and timeframe. Achievable potential answers the question, “How much DER could we reasonably reach?” – but it does not determine whether that DER can perform reliably enough to meet a specific grid constraint, which is the role of operational potential based on probabilistic analysis.

A.3 Small Customer GER Operational Potential

GER operational potential is the portion of achievable GER that can be relied upon, with high confidence, to meet a specific distribution grid need at a defined location, time, and duration. Unlike achievable potential, which estimates how much DER could be enrolled in programs or rates, operational potential answers a stricter engineering question: how much capacity a portfolio of GER can dependably deliver under real-world conditions. The paper defines operational potential using probabilistic analysis that models device behavior, customer participation, state-of-charge limits, weather sensitivity, and correlated performance across small, localized populations. Monte Carlo methods produce time-resolved performance distributions for individual technologies and multi-technology portfolios, from which exceedance-based metrics (e.g., P90) are derived. These percentile values translate inherently variable GER into accredited, infrastructure-grade capacity that can be compared to traditional grid assets. Operational potential is therefore used to determine whether a GER portfolio can reliably substitute for or defer a specific wires investment, and to quantify the residual uncertainty that must be covered through explicit DPR or complementary firming resources.

A.4 Implementation Planning and Development

Implementation planning and development translate accredited small customer GER operational potential into deployable distribution solutions by integrating commercial design, orchestration strategy, and cost-effectiveness analysis. At this stage, utilities and regulators identify the appropriate sourcing approach—through rates, utility programs, procurements, and/or flexibility markets—and evaluate each option’s feasibility across customer participation, market competitiveness, regulatory fit, and implementation complexity. In parallel, planners assess how flexibility will be operationalized, comparing price-based, direct control, and autonomous dispatch mechanisms, along with the technical platforms required to support them. Candidate solutions are then subjected to benefit-cost analysis that accounts for capital and operating costs, avoided or deferred utility investments, and direct and indirect impacts on ratepayers and society. The outcome is a set of selected GER solutions that collectively meet the defined grid need with risk-adjusted reliability while minimizing total cost, forming the portfolio to be implemented for distribution operations.

A.5 Distribution Operations

An essential aspect of distribution operations is assessing the performance of the small customer GER solution(s). This involves assessing the operational performance of the solution portfolios against the specific grid need(s), both prospectively through probabilistic model-based simulations (operational potential) and ex post, typically annually, to determine operational performance and inform accreditation modeling for the next planning cycle.

Appendix B – ISO/RTO GER Accreditation Frameworks

B.1 Purpose and Scope

U.S. Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs) are evolving resource accreditation frameworks to address the growing role of variable, energy-limited, and aggregated grid edge resources (GER) in bulk-power system reliability planning. This Appendix focuses on what ISO/RTOs are attempting to solve, why existing accreditation approaches have become insufficient, and how accreditation frameworks are being restructured to reflect changing resource characteristics and policy drivers.

B.2 Accreditation Objectives: Bulk System vs. Distribution Planning

In bulk power systems, accreditation frameworks are designed to support system-wide resource adequacy by quantifying how a resource contributes to maintaining reliability under uncertain operating conditions. That premise no longer holds. ISO/RTO systems are now characterized by rapidly increasing penetrations of:

Variable renewable generation with weather-dependent output,

Energy-limited storage resources,

Flexible load-side resources and aggregated grid edge resources (GER),

Hybrid and co-located resources with complex operating constraints.

These resources exhibit time-dependent availability, duration limits, and correlated performance under stress conditions, which are not well captured by traditional accreditation methods. As a result, ISO/RTOs face a growing risk that capacity values used for planning and market clearing may overstate or misrepresent actual reliability contribution during system stress events.[51]

B.3 Drivers of Accreditation Reform

ISO accreditation reform efforts are being driven by a combination of reliability experience, policy mandates, and forward-looking planning concerns, including:

- Observed performance gaps during extreme weather and scarcity events, where accredited capacity did not perform as expected;
- Federal policy directives, most notably FERC Order 2222, requiring ISO/RTOs to enable participation of aggregated GER in wholesale markets while ensuring system reliability;
- State decarbonization and clean energy mandates, accelerating the retirement of conventional generation and increasing reliance on variable and flexible resources;
- Changing net-load risk profiles, with tighter operating margins and more frequent reliance on energy-limited resources to meet peak and ramping needs.

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[51] NERC, *2023* *Long-Term Reliability Assessment*

Together, these drivers have forced ISO/RTOs to reassess how accredited capacity is defined, measured, and relied upon in system adequacy planning.[52]

B.4 Moving Toward Risk-Based and Probabilistic Accreditation

ISOs are increasingly moving away from accreditation approaches based solely on nameplate capacity, seasonal averages, or static derating. Instead, emerging frameworks emphasize risk-based accreditation, in which a resource's value is tied to its contribution to maintaining reliability under uncertain and stressed conditions.

Use of probabilistic system adequacy modeling to evaluate how different resource types affect reliability outcomes is growing. These approaches allow explicit accounting for uncertainty in:

- Availability during high-risk hours,
- Coincidence of resource output with system needs,
- Duration and energy constraints,
- Correlated performance across large fleets of similar resources.

- Aggregated GER, demand response, and other flexible resources present an accreditation challenge. These resources often:
- Are geographically dispersed,
- Exhibit heterogeneous performance characteristics,
- Depend on customer behavior and external conditions,
- Provide value primarily during limited windows rather than continuously.

ISOs have increasingly acknowledged that accrediting such resources using static or average assumptions risks overstating their reliability contribution. As a result, ISO/RTO frameworks are incorporating mechanisms to evaluate when, for how long, and with what probability aggregated resources are available during system stress conditions.[53] Collectively, these changes signal a shift from accrediting resources based on installed capability to accrediting them based on performance during system stress.

B.5 Accreditation by Technology Type

ISOs typically accredit resources at the registered market-resource level, but the accreditation rules are almost always grounded in technology or resource class characteristics (e.g., demand response, storage, variable generation). As a result, even when mixed-technology GER portfolios (potentially consisting of technology-specific GER aggregations) are permitted, their accredited capacity is generally constructed from technology-specific components and then summed or adjusted at the aggregation level, rather than treated as a single undifferentiated portfolio.

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[52] FERC, Order No. 2222: *Participation of Distributed Energy Resource Aggregations*

[53] MISO, *Resource Accreditation Design White Paper*

B.6 ISO/RTO Accreditation Summary

Across U.S. ISO/RTOs, accreditation frameworks are being redesigned because traditional capacity metrics no longer reflect system reliability when resources are variable, energy-limited, and increasingly aggregated. While implementation approaches differ, ISO/RTOs share a common objective: ensuring that accredited capacity reflects performance during credible system stress conditions.[54] Importantly, even where mixed-technology GER aggregations are permitted, accreditation generally remains grounded in technology-specific performance characteristics rather than treating portfolios as a single undifferentiated resource.

Table B-1 summarizes ISO/RTO-specific accreditation approaches relevant to aggregated GER and flexible resources, highlighting objectives, motivations, structural features, and current implementation status (as of December 2025).

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[54] NREL, *Probabilistic Resource Adequacy Methods for Power System Planning*

Table B-1. ISO/RTO GER accreditation summary.

ISO	Primary Objective	Key Driver	Structure	GER Portfolio Accreditation	Probabilistic Approach	Status
CAISO	Align Resource Adequacy (RA) accreditation with hourly reliability needs under high renewable penetration	Increasing evening net-load risk, storage saturation, and GER growth	Resource Adequacy based on Net Qualifying Capacity, deliverability, and hourly reliability requirements.	No current pathway for GER aggregations to qualify for Resource Adequacy; mixed-technology GER portfolios are not yet eligible.	ELCC-based modeling for renewables; evolving probabilistic RA modeling under RAMPD	GER aggregation enabled for markets; RA eligibility for GER aggregations remains under development.
MISO	Improve capacity accreditation accuracy under resource mix transition	Declining thermal margins, increased reliance on variable and flexible resources	Two-step accreditation framework combining probabilistic reliability modeling with resource-level allocation.	Heterogeneous-aggregation treatment is being developed through stakeholder process	LOLE-based modeling; marginal reliability contribution	New accreditation framework approved; full implementation planned later this decade.
PJM	Ensure capacity market reliability under increased renewables and demand response	Capacity performance failures and increasing uncertainty	Capacity Performance framework with ELCC-based accreditation for variable resources.	Allows GER Capacity Aggregation; accredited capacity constructed by summing the technology-specific component values.	ELCC-based studies for renewables; probabilistic treatment of outage risk	ELCC-based accreditation implemented; GER aggregation participation expanding.
NYISO	Accredit energy-limited and flexible resources accurately for RA	Rapid growth in storage and GER portfolios	ICAP-based accreditation with duration and availability adjustments.	Considering GER portfolio accreditation based on summed individual ICAP values with an aggregation-level adjustment.	ELCC and probabilistic adequacy modeling in planning studies	Storage and GER participation are increasing; accreditation reforms ongoing.
ISO New England	Align capacity accreditation with winter reliability risk	Fuel security and energy limitations during cold weather	Seasonal capacity qualification with performance incentives and penalties.	Heterogeneous GER aggregation participation is contemplated; capacity accreditation reforms are ongoing.	LOLE-based studies; seasonal risk weighting	Probabilistic methods in use; DER aggregation participation expanding incrementally.

Appendix C – References

California Independent System Operator (CAISO)

1. California Independent System Operator (CAISO), *Tariff, Section 40: Resource Adequacy Demonstration for Scheduling Coordinators*, as amended (describes RA obligations, Net Qualifying Capacity, and compliance requirements).
2. CAISO, *Distributed Energy Resource Provider (DERP) Participation Guide and Checklist* (provides requirements and procedures for aggregated DER participation in CAISO markets).
3. CAISO, *Distributed Energy Resources Overview*, https://www.caiso.com/generation-transmission/generation/distributed-energy-resources (overview of DER participation pathways and coordination with distribution utilities).
4. CAISO, *Resource Adequacy Modeling and Program Design (RAMPD) Initiative – Track 1 Straw Proposal* (June 6, 2025) (describes proposed reforms to RA modeling and accreditation methods).
5. CAISO, *RAMPD Track 1 Final Proposal* (September 26, 2025) (documents adopted direction and implementation timeline for RA modeling reforms).
6. California Public Utilities Commission (CPUC), *2025 Resource Adequacy Slice-of-Day Filing Guide* (policy driver reshaping hourly RA obligations that interact with CAISO accreditation).
7. CAISO, *Special Report on Battery Energy Storage Resources* (May 29, 2025) (documents operational experience and reliability implications motivating accreditation reform).

Midcontinent Independent System Operator (MISO)

8. Midcontinent Independent System Operator (MISO), *Resource Accreditation Design White Paper, Version 2.1* (March 28, 2024) (primary design document describing the Direct Loss of Load–based accreditation framework).
9. MISO, *Draft Resource Accreditation Design White Paper* (May 2023) (earlier design iteration providing background on accreditation reform evolution).
10. MISO, *Order No. 2222 Compliance Framework* (April 17, 2024) (describes MISO’s approach to enabling DER aggregation participation in wholesale markets).
11. MISO, *Overview of Changes for FERC Order No. 2222* (April 18, 2024) (high-level summary of tariff and market design changes).
12. MISO, *Order No. 2222 Tariff Redline Review and Workshop Materials* (March 26, 2024) (detailed implementation materials supporting DER aggregation participation).

PJM Interconnection

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16. PJM Interconnection, *FERC Order No. 2222 and Distributed Energy Resources* (March 5, 2025) (overview of PJM's compliance approach and participation rules).

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17. New York Independent System Operator (NYISO), *Capacity Accreditation* webpage (describes NYISO's evolving approach to aligning capacity accreditation with reliability needs).
18. NYISO, *DER and Aggregation Participation Model* webpage (overview of market participation pathways for DER aggregations).
19. NYISO, *DER and Aggregation Participation Model – Frequently Asked Questions* (provides explanatory guidance on aggregation rules and requirements).
20. NYISO, *Aggregation Manual (Manual M-38)* (procedural manual governing aggregation participation and operations).
21. NYISO, *Installed Capacity (ICAP) Manual* (foundational description of capacity market rules and accreditation mechanics).
22. NYISO, *Capacity Accreditation Conceptual Framework* (Potomac Economics, 2021) (discusses ELCC concepts and reliability-based accreditation logic).
23. NYISO, *Order No. 2222 Compliance – Phase 1 Filing and Implementation Materials* (describes compliance scope and timeline).

ISO New England (ISO-NE)

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26. ISO-NE, *Order No. 2222 Overview and Implementation Update* (September 13, 2024) (status update on DER aggregation participation).
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Federal / Other Policy Drivers

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