Think Globally, Shift Locally: Opportunities and Barriers to Implementing Localized Load Flexibility Programs as a Grid Resource

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ABSTRACT

This paper describes opportunities and barriers for the development of localized load flexibility programs, tariffs and resources to offer grid planners and operators grid resources to relieve distribution congestion, improve localized reliability, and defer and/or avoid distribution upgrades. The rapid adoption of new clean energy technologies such as heat pumps, electric vehicles, data centers and solar has the potential to require vast amounts of new distribution grid investment to ensure the grid stays reliable and resilient in response to changing loads at the local level. Hope remains that load flexibility can be implemented at scale as the lowest cost solution to solving this vexing problem and therefore avoid further increasing utility bills. This paper summarizes results from an industry-led load flexibility task force examining how to value load flexibility as a local resource. This work has demonstrated the need for smart methodologies to measure the planning and operational value load flexibility brings to the grid. The paper provides case studies of utilities, state programs and research organizations modeling localized benefits of load flexibility and opportunities and barriers to realizing these values. These case studies have demonstrated that there are many effective approaches to localized valuation being applied across the industry including modeling of cost-effectiveness deferral value for grid services compensation, borrowing bulk system concepts of resource adequacy for the distribution system using probabilistic modeling, developing digital twins of the grid to avoid substation upgrades and modeling of load flexibility to increase speed to power of large loads.

Introduction

The electric grid of today faces unprecedented challenges from the rapid rise of new electric loads and the simultaneous growth of variable renewable energy such as wind and solar. After nearly two decades of flat electricity demand, the U.S. has entered a growth era that is straining grid infrastructure at both the bulk and local distribution levels. The Department of Energy (DOE) projects total U.S. electricity demand could grow 15–20% over the next decade, driven by AI, data center expansion, domestic manufacturing, and broad electrification across transportation and buildings (DOE 2024). New loads, from heat pumps and EVs to large industrial facilities, are arriving simultaneously with a rapid build-out of wind and solar that introduces new planning complexity at every level of the grid. NERC has warned that as conventional generation retires and is replaced by variable wind and solar, traditional capacity-based resource adequacy criteria are becoming increasingly misaligned with evolving needs, because variable resources alone cannot reliably provide the voltage support, frequency response, and flexibility the grid requires (NERC 2024).

These drivers are creating acute impacts at the local distribution level, where existing infrastructure was never designed to absorb concentrated, high-density load or the cumulative effects of distributed resources such as EV charging, rooftop solar, and battery storage. At the local level, the consequences of large load growth are already materializing: NERC documented a 1,500 MW load loss event across 25 substations in Loudoun County, Virginia in July 2024, and an 1,800 MW event in the same region in February 2025, both driven exclusively by data center load (NERC 2025a).

Meeting projected demand will require massive capital investment with U.S. investor-owned utilities projected to invest more than $1.1 trillion in grid infrastructure, spanning generation, transmission, and distribution systems, including power lines, substations, transformers, and grid modernization technologies, between 2025 and 2029 (EEI 2025), yet capital-intensive grid expansion alone is neither fast enough nor cost-effective enough to match the pace of load growth.

While it is tempting to look to the legacy playbook of simply building additional grid infrastructure through bulk transmission expansion and local distribution system reinforcement, there is growing concern that this will lead to affordability challenges—specifically through unsustainable increases in electricity rates to pay for this new infrastructure (EEI 2025; EIA 2024). Many are looking to an alternative approach that leverages these same distributed resources for load flexibility to help mitigate grid constraints and limit investments in new "poles and wires."

For the purposes of this paper, we define load flexibility broadly as the ability for customers to adjust their energy usage in response to grid conditions or signals, in ways that provide measurable value to the electric or gas system. Load flexibility has historically been designed to address system-level supply-demand balancing and, more recently, to mitigate localized capacity constraints and reliability issues. The way flexibility is delivered varies depending on the nature of the constraint. In many cases, flexibility is enabled through incentives or price signals that influence customer behavior. In others—particularly where highly localized constraints exist at the level of feeders or transformers—more direct coordination of distributed resources with available capacity may be required to ensure limits are not exceeded. These approaches can be viewed as part of a broader load flexibility toolkit, reflecting a continuum from purely behavioral to price-responsive to more directly managed solutions. In this context, load flexibility is treated as a capability, independent of the specific technologies providing it, and is ultimately evaluated based on its aggregate impact on the grid at the meter or system level.

However, questions remain among regulators, planners, and operators about whether load flexibility can be a cost-effective and reliable resource for the electric grid at scale. In the current regulatory framework, it is essential that load flexibility champions demonstrate the cost-effectiveness of load flexibility across multiple stakeholder perspectives by showing that the benefits of these technologies outweigh the costs. While many of the costs are well-known and straightforward to quantify (e.g., customer acquisition, program administration, marketing, incentives, technology upgrades), the program benefits can be hard to quantify. These hard-to-quantify benefits include infrastructure deferral, reliability and resiliency, regulatory and policy achievement, customer well-being values, and more.

In response to these valuation challenges, PLMA, a member-led 501(c)(6) nonprofit association for flexible load management specialists,[1] launched a new Load Flexibility Valuation Strategic Initiative, to help address these challenges and ultimately drive scale. The first area of focus for the strategic initiative has been on defining the locational value of load flexibility, recognizing that "locational" can span multiple levels of the grid, including specific distribution assets (e.g., feeders, substations, or even individual transformers) and has pulled together utilities, vendors, consultants, researchers and state governments to collect use cases, value streams and calculation methodologies for the locational value of load flexibility. The initiative has been sharing these outputs through workshops and presentations at PLMA conferences and regular meetings of the strategic initiative taskforce. The taskforce is currently working to publish a compendium that includes a local valuation framework and case studies of current initiatives tackling these challenges. This paper provides a summary of these results to date and a preview of content under development for the compendium.

Overview of PLMA Load Flexibility Valuation Strategic Initiative

PLMA's Load Flexibility Valuation Strategic Initiative ("LF Valuation") was launched in Fall 2024 as part of PLMA's 2024-2026 Strategic Vision (Figure 1).

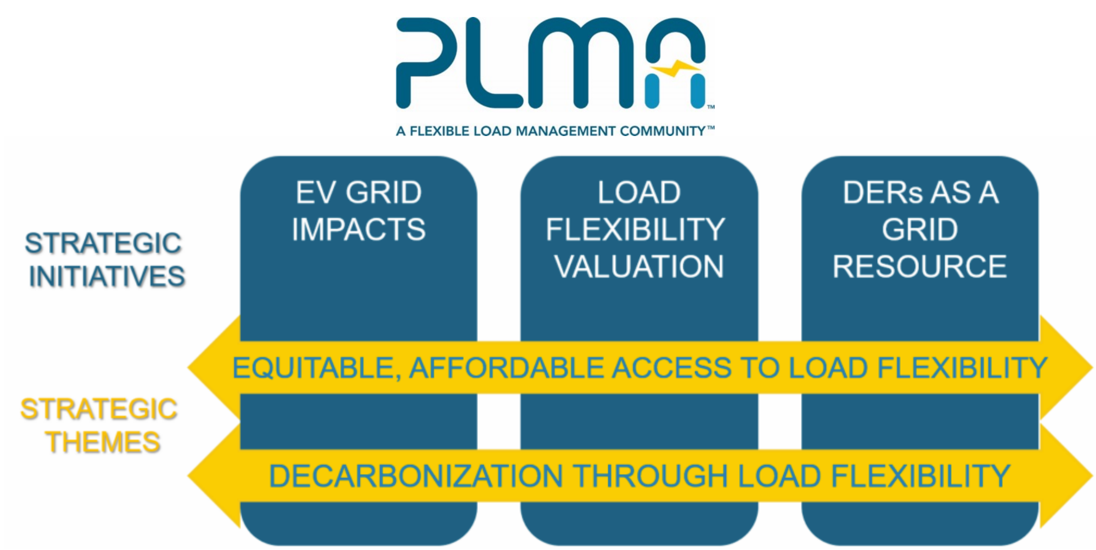

Figure 1. PLMA Strategic Vision (2024-2026)

[1] PLMA (https://flexload.org/) is dedicated to advancing grid reliability, resiliency and affordability through flexible load management, including distributed energy resources (DERs), virtual power plants (VPP), and managed charging innovation, by sharing best practices, hands-on experiences, technology advances, training, mentorship, and leadership opportunities.

The initiative was created under the hypothesis that the industry's ability to scale load flexibility is limited, in part, by limitations in adequately valuing its contributions to customers and the grid. This hypothesis was initiated through workshops that PLMA conducted in Spring 2020 with Rocky Mountain Institute (RMI) on the barriers to DER adoption under PLMA's Spark DER Strategic Initiative (now DERs as a Grid Resource), then supported through subsequent years of PLMA member engagement. LF Valuation thus adopted the following charter: "Provide PLMA members with a forum and content to advance load flexibility valuation by reducing key barriers and sharing case studies and insights across multiple stakeholder perspectives."

Strategic Initiative Focus

At PLMA's Fall 2024 conference, LF Valuation hosted a workshop that sought to confirm and refine this hypothesis, and gather member input on the most challenging and impactful value streams for the Initiative's initial focus. Figure 2 presents the workshop responses, with T&D Infrastructure Deferral, Reliability, and Customer Impacts identified as the most impactful for scale, but with some challenges in incorporating.

Figure 2. PLMA Categorization of Value Streams by Impact and Challenge
Note: Based on 97 responses. #6: T&D Infrastructure Deferral is shown under #9: Reliability.

Based on these findings, LF Valuation selected Locational Value as its initial area of focus, to reflect both T&D Infrastructure Deferral and Reliability benefits at a localized level.

Overview of Locational Value

Through feedback from the workshops and LF Valuation Task Force, the PLMA LF Valuation Leads developed the following hypothesis for locational valuation: "Existing frameworks do not fully capture the benefits associated with localized load flexibility."

Without a complete understanding of the benefits of localized load flexibility, it is difficult to effectively compare it with traditional grid infrastructure and determine whether these alternative flexibility interventions are more cost-effective. Determining cost-effectiveness requires both an understanding of the costs of these programs, which are generally well understood, and an understanding of the value they bring to the local grid, which is generally less well understood. If locational value can be better articulated and cost-effective localized interventions can be identified, this would reduce significant barriers to the scaling of load flexibility, which has the potential to more cost-effectively serve new load, help reduce utility rates, and enable more affordable future load growth.

While there are existing frameworks for the value of distributed resources, these frameworks are structured around specific technologies rather than the flexibility these technologies enable. As a result, they are either too broadly applicable across distributed resources or too specific to certain technologies—and the Task Force identified no frameworks specific to load flexibility.

Furthermore, the application of load flexibility for locational or geotargeted dispatch is still relatively nascent in the industry, with its use cases and value streams rapidly evolving across planning and operations. For example, when we launched this work in Fall 2024, the concept of bridging (e.g., bridge-to-wires, bridge load, bridging strategies, speed-to-power, etc., where flexibility serves as a stopgap while traditional T&D infrastructure is developed) was relatively emergent—and is now a ubiquitous concept due to the accelerated growth of electrification and data centers.

The following examples illustrate the importance of investigating the 'missing benefits' for load flexibility:

- Utilities recognize the value of EV managed charging programs and tariffs for managing distribution impacts, but are often unable to demonstrate the value on paper.
- Utilities are increasingly dispatching geotargeted flexibility events on a specific feeder for localized reliability benefits, without an explicit non-wires alternative project, but do not have a consistent valuation approach for this use case.
- There is an emerging need to identify value streams for bridge-to-wires and develop locational pricing signals (e.g., for flexibility markets operated by Distribution System Operators (DSO) at the distribution level).

The industry is actively assessing whether flexibility can effectively avoid or defer T&D-level infrastructure investment in practice, given the 'Goldilocks' nature of timing (i.e., the availability of the flexibility resource must line up with the timing of the infrastructure need). We agree that this is an important question to answer—and that there are also other additional value streams we must assess to understand the complete value stack for localized load flexibility.

To successfully identify cost effective opportunities to defer T&D-level infrastructure with load flexibility, there needs to be a shift in approach to valuing load flexibility resources, as illustrated in Figure 3.

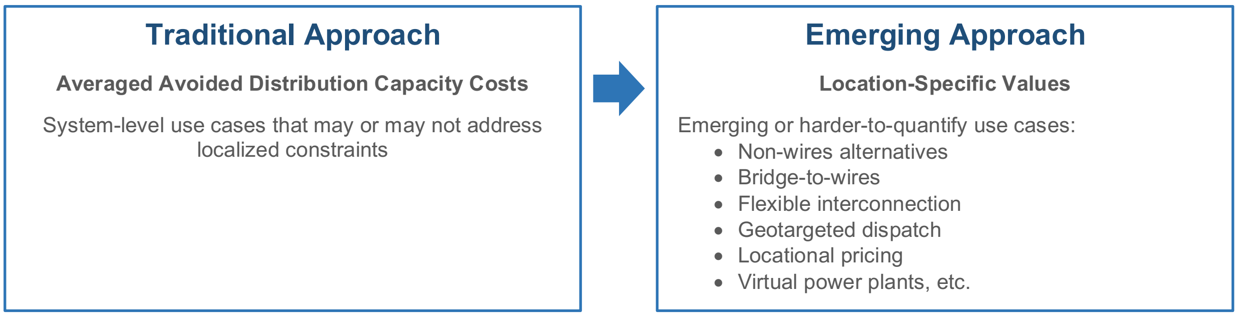

Figure 3. Shift in Approach to Valuing Locational Benefits of Load Flexibility

Locational Value framework

To offer a common language and advance the industry's understanding of locational value, PLMA is developing a framework for considering the use cases, stakeholder perspectives, value streams, and grid services associated with locational load flexibility value. This DRAFT framework is illustrated in Figure 4.

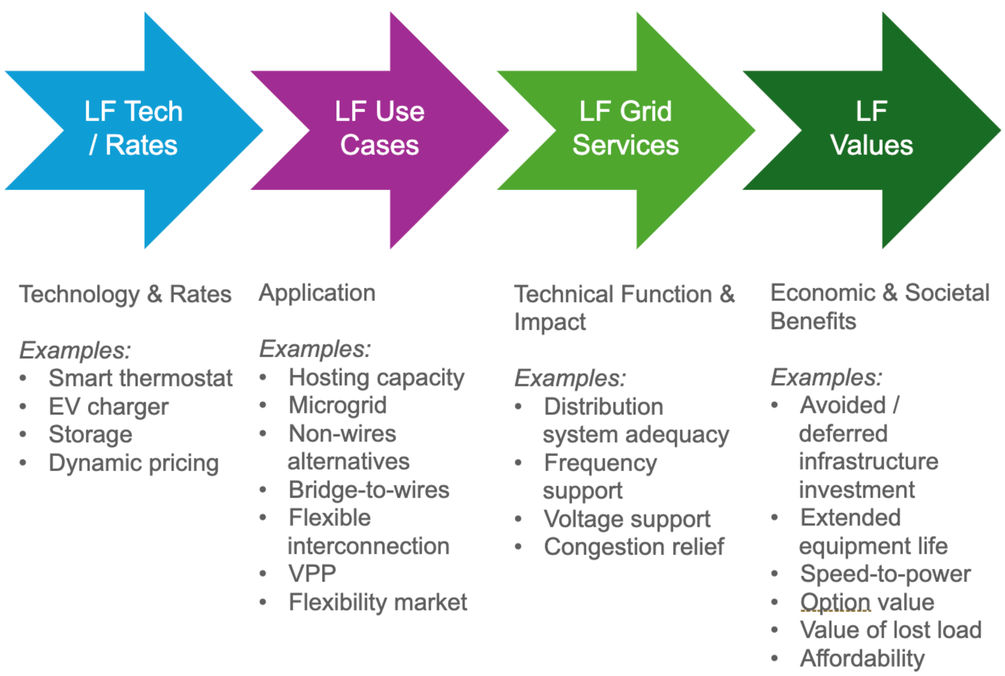

Figure 4.Visualization of PLMA Load Flexibility Draft Valuation Framework

Locational Valuation Case Studies

This paper offers four case studies on locational valuation sourced from PLMA member-led presentations from recent conferences, including conference workshops specific to LF Valuation. Notably, these case studies were drawn from PLMA member presentations rather than peer reviewed research.

Case Study 1: Valuing Load Flexibility in Massachusetts

A state-led collaboarative initiative by the Massachusetts Clean Energy Center (MassCEC) focused on valuing distribution-level load flexibility to design compensation frameworks for Distributed Energy Resources (DERs). MassCEC led the initiative and convened a cross-sector project team that included National Grid, Eversource, Unitil, the Massachusetts Department of Energy Resources, and the Massachusetts Attorney General's Office and engaged with E3 and RMI as the consultant team.

The core goal of the work was to determine how to value flexibility at the local level and how customers can be compensated for the services DERs may provide to the electric grid. They specifically targeted two local capacity-constraint scenarios: "Investment Deferral," where DERs provide capacity to delay or avoid long-term traditional utility investments (see Figure 5), and "Bridge-to-Wires," where DERs meet near-term capacity needs before a physical infrastructure solution is completed. This work culminated in a report and grid services valuation model published in September 2025, which provides frameworks for valuing and compensating DERs, including load flexibility, for distribution grid services (MassCEC 2025).

This work included the following methodologies:

- **Cost-Benefit Analysis Framework:** The study used a cost-benefit framework focusing on revenue requirement impacts (e.g., deferral value, avoided backup generation). Deferral value was calculated based on the discounted value of the deferred investment (Net Present Value) using utility weighted average cost of capital.
- **Price Ceilings and Floors:** The methodology established a recommended compensation "ceiling"—the total value to the grid minus the administrative costs of the programs. They also established a "floor"—the opportunity cost for the DER to dispatch for local distribution grid needs instead of based on other signals. Spend on Grid Services should fall between these two markers to support participation while ensuring net ratepayer savings.
- **Environmental Justice (EJ) Adders:** To advance equity, the methodology included EJ adders to support participation in disadvantaged communities. Because these adders reflect non-rate impact values, the effective price ceiling for non-EJ participants would need to be adjusted downward by subtracting the EJ adder, ensuring the total cost stays within the limit set by rate impacts.

This work produced the following insights for determining the value of load flexibility:

- **Locational Value is Essential:** Grid services must be location-specific; while some areas have significant value for grid services, other areas of the grid will have none. Also, the value at a specific location is transient, only persisting for as long as the alternative investment can be deferred or a bridge-to-wires solution is required.

- **Net Cost Thresholds:** If the administrative costs plus the compensation price floor exceed the value provided to the grid, it is inefficient to pay DERs for grid services, and these solutions should not be pursued.
- **Value Streams Include Rate and Non-Rate Impacts:** As shown in Figure 6, grid service use cases may directly impact rates (e.g., through deferral value or other avoided costs) or provide value beyond rate impacts (e.g., through environmental justice, value of lost load, or air quality benefits).
- **Optionality and Incremental Investment:** Relying on DERs allows planners to make incremental, right-sized investments rather than massive long-term commitments. This provides an "optionality benefit," allowing utilities to wait and see how local system needs actually develop.

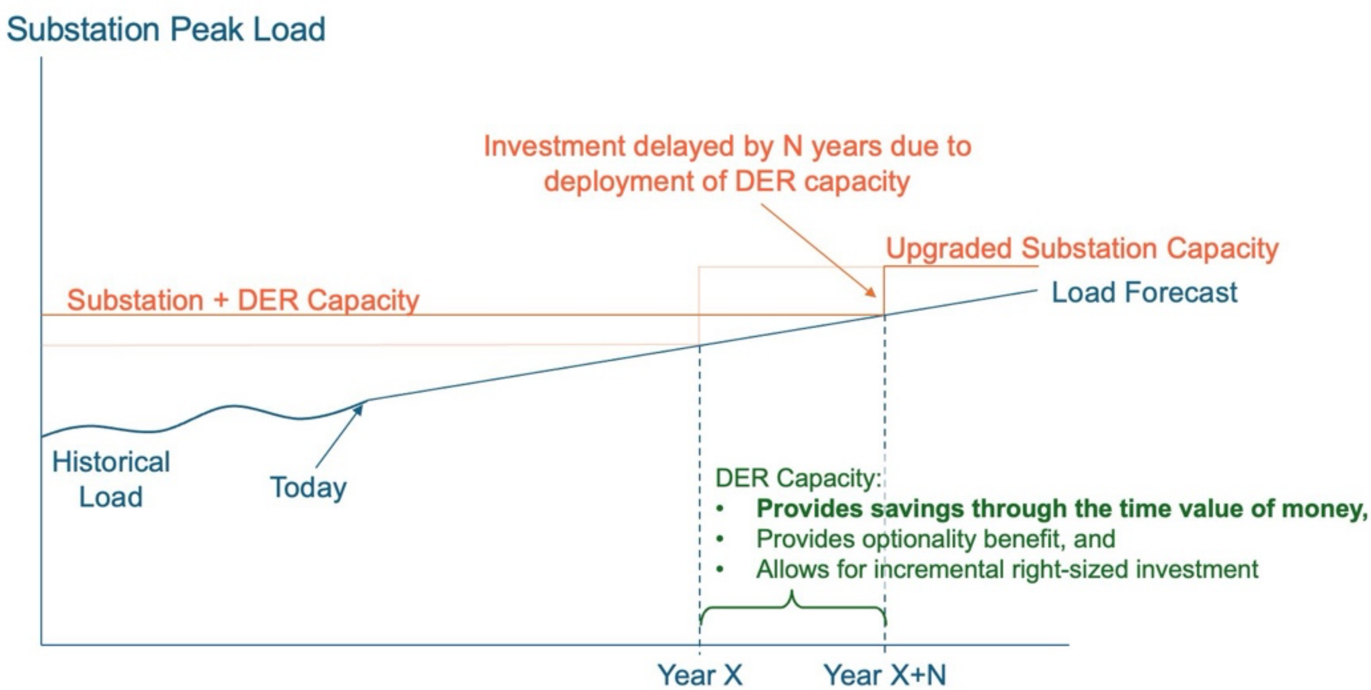

Figure 5. Modeling Investment Deferral of DERs and Load Flexibility

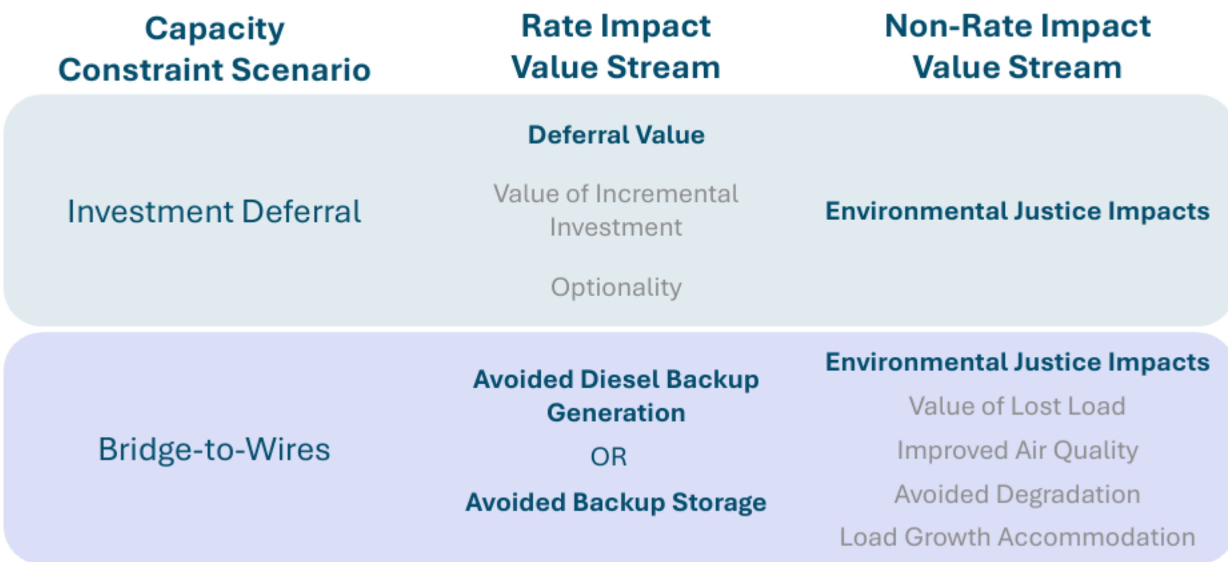

Figure 6. MassCEC Valuation Framework for DER Grid Services

Case Study 2: Distribution System Adequacy

The National Laboratory of the Rockies (NLR), formerly the National Renewable Energy Laboratory, and Lawrence Berkely National Laboratory (LBNL) are reframing how utilities can evaluate distribution upgrades by developing a framework they call "Distribution System Adequacy" (DSA), which is meant to be similar to bulk level Resource Adequacy, but at the local level. DSA aims to create a level playing field to compare the capacity and risk of traditional utility upgrades against non-traditional DER solutions like load flexibility. NLR and LBNL defined DSA as the ability of a primary and secondary distribution system to transport load from transmission or subtransmission substations to end users with prescribed power quality and continuity.

This work included the following methodologies:

- **Transition from Deterministic to Probabilistic Modeling:** Traditional distribution planning relies on deterministic peak load forecasting (worst-case scenarios). NLR and LBNL proposed using Monte Carlo simulations to represent distribution grid performance and its load and resources as random variables dependent on weather, load profiles, DER profiles, and grid asset outages. The case studies did, however, highlight that the DSA framework can complement deterministic planning approaches, making it compatible with current utility planning methodologies.
- **Bulk Power Concepts Applied to Distribution:** NLR/LBNL adapted bulk power "Resource Adequacy" metrics and methods—like Effective Load Carrying Capability (ELCC)—to the distribution level.
- **DSA Accreditation Score:** Solutions are evaluated using risk metrics such as Yearly Expected Unserved Energy, Conditional Value at Risk, Yearly Voltage Violation Risk,

and Yearly Thermal Violation Risk. These outputs are used to assign a "DSA Accreditation Score" (e.g., 95% for reconductoring a feeder vs. 90% for adding a battery). The impact of grid and customer-sited resources on DSA is called the Contribution to DSA (CDSA), which is the equivalent of ELCC.

- **Accreditation Components:** The methodology specifically accounts for the Peak Load Alignment of DER (e.g., solar output might be limited during evening hours), DER Dependability (e.g., DER forced outage or communication failures), and Network Effects (e.g., network outages or capacity constraints).

This work produced the following insights for determining the value of load flexibility:

- **Risk Must be Quantified:** Different solutions carry different risks, and deterministic worst-case modeling unfairly tilts the playing field. The DSA framework can help evaluate traditional solutions (such as reconductoring) against non-traditional solutions (such as DER) by accounting for their stochastic behavior and how it matches probabilistic grid needs

- **Network Effects:** When evaluating different grid upgrades, it is important to consider how those upgrades interact with the distribution network to affect both power quality and continuity. For instance, DER placed on a lateral may increase DSA if placed in a strategic location that takes advantage of distribution network reconfiguration options; it can also decrease DSA if those DER are placed on an unreliable lateral that prevents DER from providing grid services.

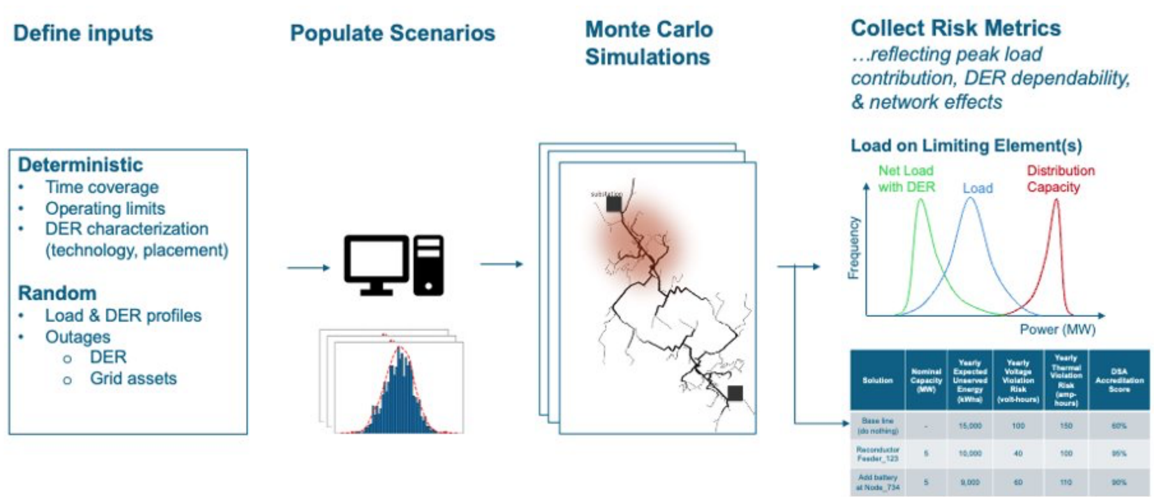

Figure 7. Proposed Monte Carlo Simulation modeling for Distribution System Adequacy

Case Study 3: Digital Twin Blueprint for Substation-Level DER Valuation

Southern Maryland Electric Cooperative (SMECO) partnered with ICF to practically assess the potential for Non-Wires Alternatives (NWA) to defer infrastructure investments using a digital twin tool. To test the tool, the team scoped a capacity deferral project at the West Brandywine Substation, a summer-peaking area experiencing massive load growth from new residential construction. The goal was to evaluate the technical efficacy of Demand Side Management (DSM) for investment deferral. The results show that these measures could keep the transformer under its thermal limit and leverage DERs to create value for members, though further study is required to assess cost-effectiveness.

This work included the following methodologies:

- **Premise-Level Digital Twins:** Instead of top-down estimations, the team built highly granular, geographically optimized "Digital Twins" of the buildings on the substation.
- **Data Aggregation:** They calibrated these models using localized Advanced Metering Infrastructure (AMI) data, overlaying it with building types (square footage, vintage, HVAC systems), and economic/environmental data (weather, Area Median Income).
- **Predictive Scenario Modeling:** The team applied a load growth forecast (e.g., adding 400 homes per year) to observe the development of future peak loads. They then modeled specific measure combinations, such as air sealing (energy efficiency) and Battery Energy Storage Systems (BESS), to calculate the exact coincident peak kW reduction achievable over a 10-year timeline.

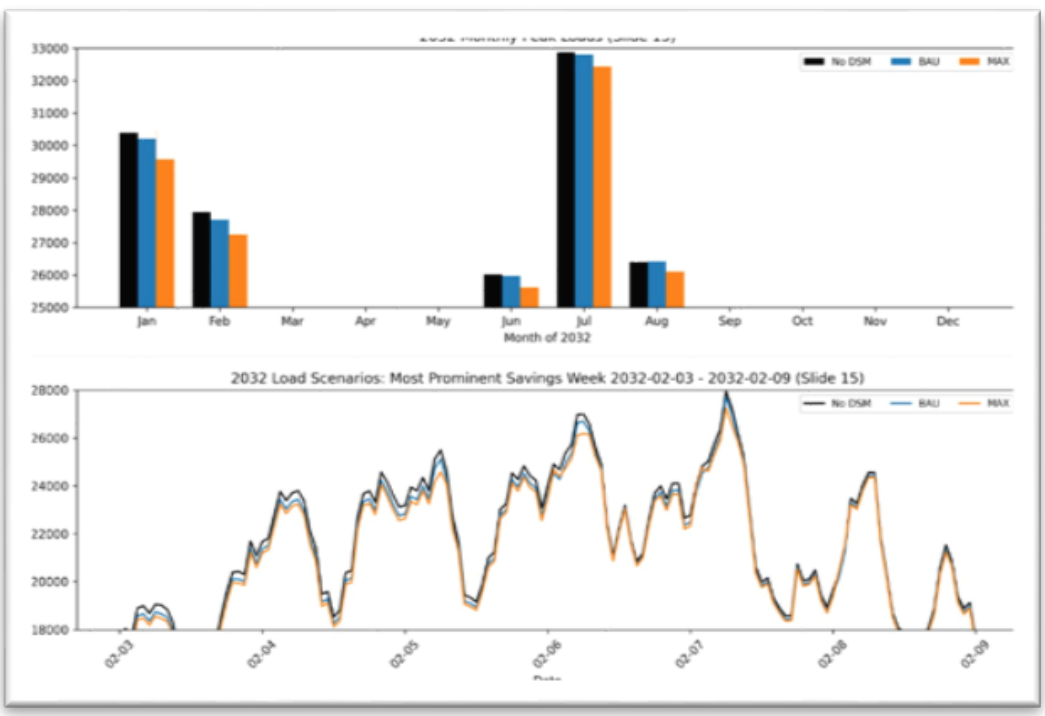

Figure 8. Modeling Results of Load Flexibility using Digital Twins

This work produced the following insights for determining the value of load flexibility:

- **Granularity is Key for Accuracy:** Digital twins that calibrate well to actual substation AMI load allow utilities to accurately verify if premise-level details match the ground reality.
- **Beyond Traditional Measures:** Highly granular data modeling helps utility planners look beyond traditionally modeled measures to evaluate complex combinations like deploying air sealing alongside battery storage for high potential peak reduction.
- **Collaborating Across Silos:** Integrated system planning using digital twins provides a holistic approach that encourages collaboration across internal utility silos, allowing companies to leverage existing DSM and DER programs to inform capital planning. Maryland's new electric system planning requirements have reinforced the value of this collaboration, and digital twins and DERs can be integral to both wires and non-wires solutions across future grid planning.

Case Study 4: Valuing Flexibility for Data Centers

Oak Ridge National Laboratory (ORNL) has developed a prototype application called the Grid Services Economic Impact Assessor (GSEIA) to model the economic impacts of load flexibility for the customer, the interconnecting utility, and associated ratepayers. Their initial assessment was based on a simulated scenario involving a hypothetical massive commercial customer: a data center with a 20 MW interconnection request intended to support AI inference workloads[2]. The technique first assesses load flexibility relative to a "base case" without leveraging load flexibility. Here, the base case is an inflexible data center, which would require an upfront $10 million substation upgrade by the distribution utility before their request could be approved, thereby delaying their energization. The "flexible case" models the same data center implementing periodic curtailment up to 6 MW of its energy usage during regional and/or system peak hours, delaying the system upgrade and perhaps entirely avoiding the cost.

This work included the following methodologies:

- **Traditional Utility Cost Tests:** The economic analysis leveraged standard regulatory metrics extrapolated over 10 years: the Participant Cost Test (PCT), Utility Cost Test (UCT), Total Resource Cost (TRC), and Ratepayer Impact Measure (RIM).
- **Rate Modeling:** The model calculated the data center's energy reduction logic against real-time locational marginal prices (LMPs), forward capacity market charges (FCM), and transmission/distribution charges.
- **Value of Lost Load (VOLL):** A crucial addition to the methodology was factoring in the customer's business opportunity cost. Because a data center loses computational revenue when it curtails energy, the model applied a VOLL of $10,000 per MWh to both the PCT and TRC tests to reflect this lost revenue potential.

[2] These findings were based on a simulated study of a synthesized data center, with assumptions about its load profile characteristics and regional load growth modeling, and do not reflect an explicit customer's characteristics.

This work produced the following insights in relation to determining the value of load flexibility:

- **Customer Opportunity Costs Dictate Viability:** Avoiding a $10 million infrastructure upgrade looks like a net positive. However, once the VOLL ($28,700,000 over 10 years) is included, the Participant Cost Test drops from positive $10.4M to negative $18.4M. This implies that if curtailment disrupts core business revenue, large customers will simply pay for grid upgrades rather than participate in flexibility.
- **With actual data centers leveraging the GSEIA tool, there is a chance to help improve the large load interconnection process:** Current interconnection studies focus on worst-case scenarios and are non-collaborative. To unlock true load flexibility, the interconnection process could be vastly improved by having parties submit fewer requests backed by more robust load shape data and determining costs and benefits collaboratively before finalizing expensive infrastructure requirements. The GSEIA tool attempts to give both parties tools to explore different flexibility strategies and different rate configurations to inform collaborative discussions.

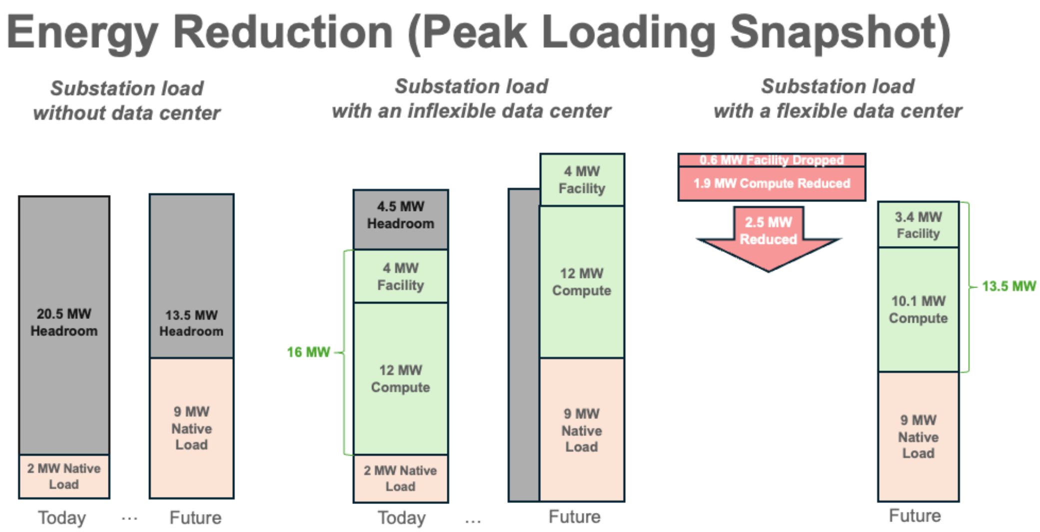

Figure 9. An Illustration of the Significance of a Flexible Data Center on the Substation Load

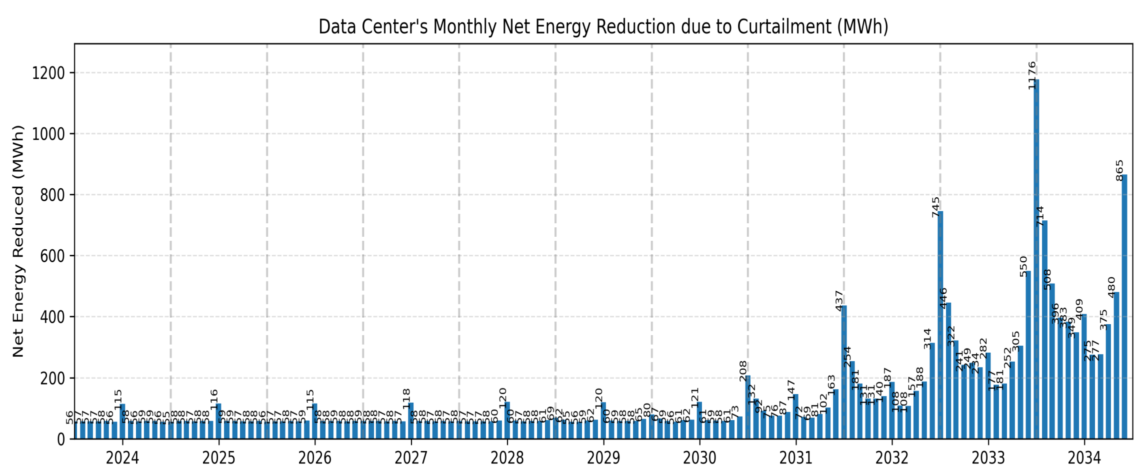

Figure 10. Modeled Curtailment of the Hypothetical Data Center Load to Support Local Distribution Grid

Conclusions / Lessons Learned

The broad interest in load flexibility valuation shows the importance of this topic to utilities, regulators, state governments and load flexibility practitioners. The PLMA LF Valuation Strategic Initiative has been successful in bringing together these diverse set of stakeholders to collaborate on these issues and share case studies and best practices.

This work has brought to light several opportunities and challenges to the advancement of LF valuation, particularly related to locational value, to recognize the variety of values these resources can provide and enable the deployment of LF at scale as a cost-effective alternative to traditional infrastructure deployment.

Barriers

The following barriers have been identified by this work to date:

- Lack of shared understanding across internal and external stakeholders about how and when load flexibility creates value at the local level for both planning and operational use cases;
- Regulatory frameworks and cost-benefit tests that are not designed for load flexibility specifically, and insufficient incentive structures to support load flexibility as a viable infrastructure alternative;
- Persistent skepticism among regulators and planners about resource reliability and availability, compounded by the difficulty of building enrolled resource bases at sufficient scale before reliability needs materialize;
- The "Goldilocks" timing challenge: load flexibility resources must be developed, enrolled, and available precisely when an infrastructure need arises — too early and the value is unrealized, too late and the deferral window has closed;
- Insufficient access to geographically granular data and inconsistent valuation planning practices across jurisdictions; and
- Compensation structures across geographic areas that can seem inequitable given that they vary across locations and in some areas the value may be none -- equity considerations can be relieved somewhat with the addition of EJ adders but that may not fully address issues with compensation that varies by customer location.

Opportunities

The following opportunities have been identified by this work to date

1. Develop an industry-accepted framework for the definition of LF valuation;
2. Develop industry-accepted best practices for the estimation of LF value to the distribution grid to support local LF resource deployment and dispatch at the local level;
3. Move past traditional deterministic modeling for reliability and interconnection to more probabilistic modeling that supports flexibility;

4. Develop valuation and compensation frameworks specific to bridge-to-wires use cases, where load flexibility serves as a near-term stopgap while traditional infrastructure is constructed;
5. Use resource valuations, costs, and EJ concerns to set standard compensation structures for LF resources alongside more traditional DERs (e.g., solar and batteries);
6. Integrate valuations with traditional cost benefit tests (e.g., PCT, UCT, TRC, RIM) for cross-industry alignment;
7. Apply concepts from the bulk power level to the determination of value at the local level;
8. Use advanced modeling techniques like digital twins and Monte Carlo simulations to determine the ability of LF to contribute to grid reliability and flexible interconnection;
9. Break down silos between utility teams to enable LF to contribute to grid planning and capital investment projects; and
10. Use VOLL to ensure LF measures are cost-effective for customers.

By creating industry alignment around the opportunities for this important topic and openly sharing results and best practices about attempts to address them, the LF industry can demonstrate where and under what conditions load flexibility can serve as a cost-effective and rapidly deployable complement to traditional grid infrastructure, to address the challenges of electrification and variable renewable generation at the local level.

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Extent: citation research
Human review: The authors reviewed and verified all content, calculations, and citations.

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