

# Gaps, Barriers, and Solutions to Demand Response Participation in Wholesale Markets



A Report from the  
Energy Systems Integration Group's  
Distributed Energy Resources  
Working Group

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# Gaps, Barriers, and Solutions to Demand Response Participation in Wholesale Markets

**A Report by the Energy Systems Integration Group's  
Distributed Energy Resources Working Group**

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To download the **online appendix** for this report, go to <https://www.esig.energy/demand-response-in-wholesale-markets>.

## Abbreviations Used

<b>CAISO</b>	California Independent System Operator
<b>DER</b>	Distributed energy resource
<b>EIA</b>	Energy Information Administration
<b>ELCC</b>	Effective load-carrying capability
<b>FERC</b>	Federal Energy Regulatory Commission
<b>IESO</b>	Independent Electricity System Operator
<b>ISO</b>	Independent system operator
<b>ISO-NE</b>	Independent System Operator for New England
<b>LMR</b>	Load-modifying resource
<b>LSE</b>	Load-serving entity
<b>MISO</b>	Midcontinent Independent System Operator
<b>NERC</b>	North American Electric Reliability Corporation
<b>NYISO</b>	New York Independent System Operator
<b>SPP</b>	Southwest Power Pool

# Executive Summary

**A**s the electricity grid transitions to accommodate more renewable energy and electrification, demand response can play a vital role in ensuring grid reliability and dampening price volatility in wholesale electricity markets. However, despite its recognized potential to help manage electricity demand, particularly during peak load periods when generation may be scarce, the actual deployment of demand response in wholesale electricity markets has stagnated or even declined in recent years.

This report examines why demand response participation remains limited in wholesale markets and proposes actionable solutions to unlock its full potential. The analysis draws from extensive interviews with industry stakeholders, including system operators, regulators, aggregators, and consumers, to (1) identify five critical gaps that must be bridged to accelerate demand response deployment, and (2) offer targeted solutions to address each gap.



## Current State of Demand Response

Despite studies that show high potential for demand response given technological advances and growing grid needs, demand response capacity is below 7% of peak load across U.S. wholesale markets. These low levels stand in stark contrast to the rapid growth of other clean energy resources like wind, solar, and battery storage that have attracted significant investment in recent years. It is important to identify the reasons behind the gap between demand response's significant promise but low deployment and to address these challenges to allow demand response in wholesale markets to provide the level of load flexibility that grid reliability requires.

Figure ES-1 shows the recent adoption levels of demand response in each of the U.S. wholesale electricity markets from 2009 through 2023. While there is variation across each system operator's loads, program rules, and size, the overall trends are similar: limited increases in demand response participation nationwide. Some have achieved demand response levels above 10%, but most have seen recent sharp declines or minimal growth from their high points. Only the California Independent System Operator (CAISO) market—which has demand response programs administered outside of the market by the California Public Utilities Commission regulatory requirements—has seen notable increases in recent years.

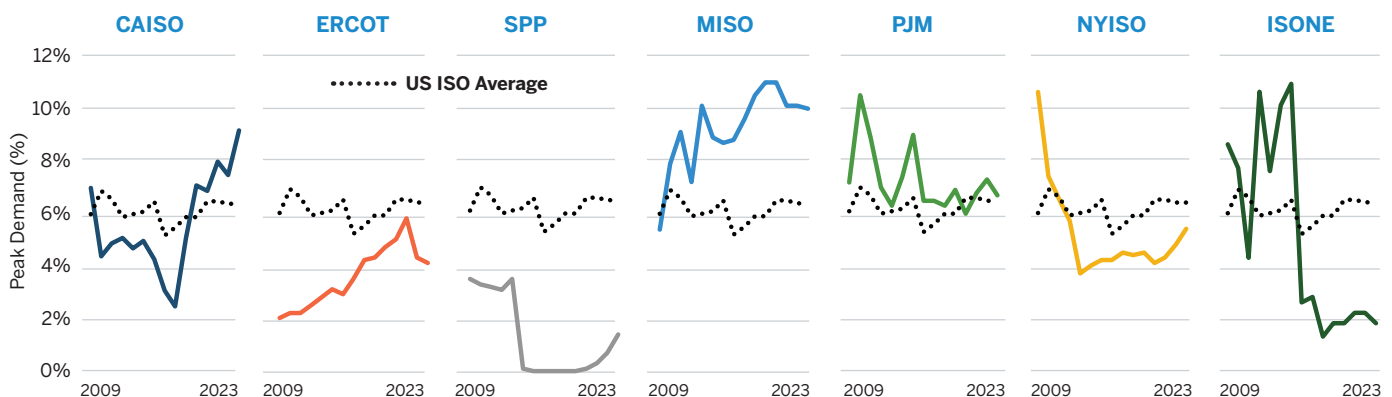
Regional variations in demand response adoption are significant, with participation rates varying widely across

different independent system operators and states. This disparity reflects both the fragmented nature of current market structures and the varying effectiveness of different policy approaches. While Figure ES-2 (p. xi) shows primarily retail demand response programs—which may or may not be included in the wholesale market—similar adoption levels are seen outside of the system operators' footprints. Participation levels across states show enrollment rates ranging between 2% and 8%, with an average of 6.5% nationwide. This figure indicates significant untapped potential for demand response to further contribute to grid flexibility and capacity needs. Interestingly, there appears to be little correlation between participation



**FIGURE ES-1**

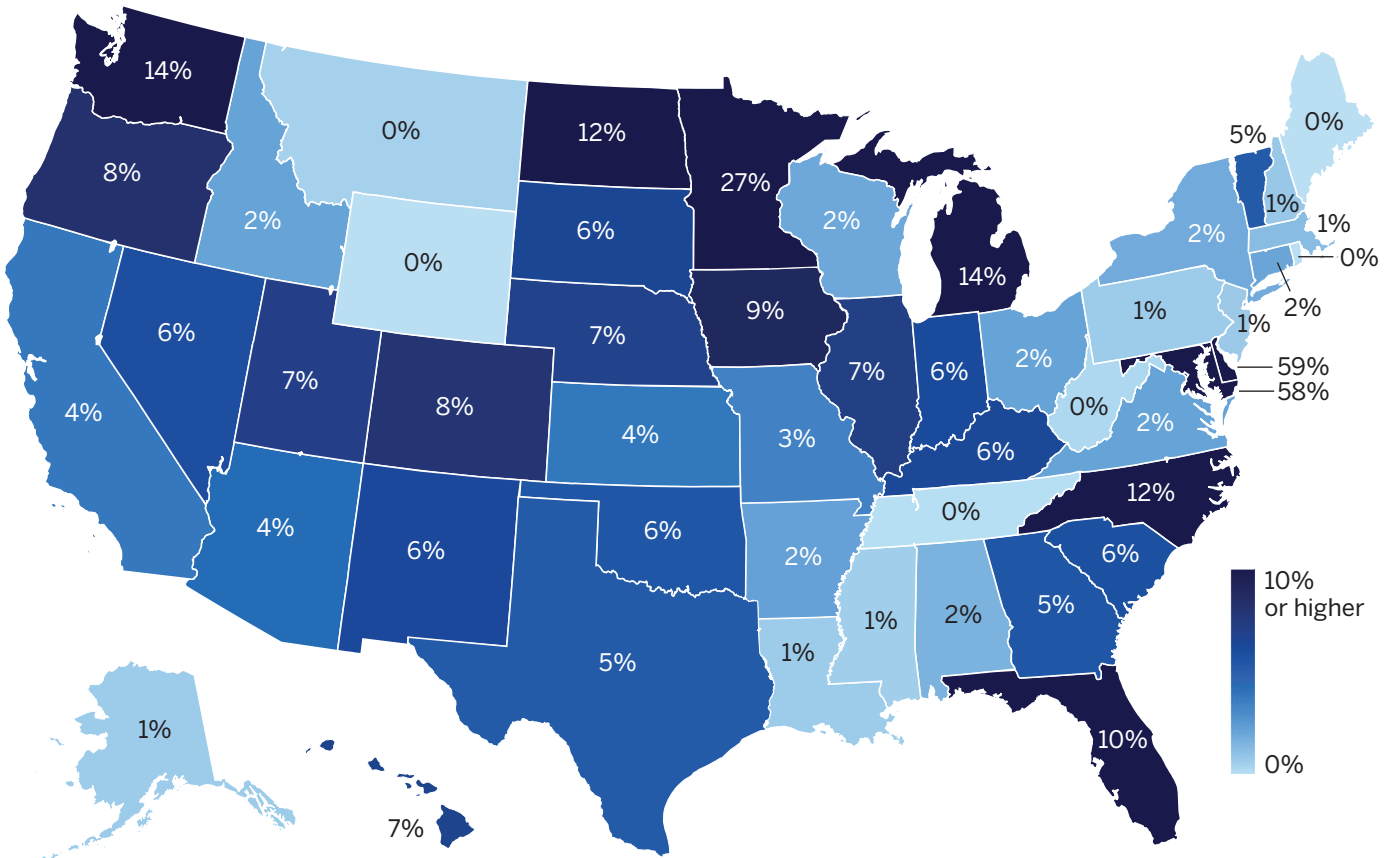
**Wholesale Demand Response Capacity by Independent System Operator as a Percentage of Peak Demand, Showing Stagnant or Declining Participation in Most Markets**



Source: Energy Systems Integration Group; data from Federal Energy Regulatory Commission's 2023 *Assessment of Demand Response and Advanced Metering* (FERC, 2023).

**FIGURE ES-2**

Percentage of Customers Enrolled in Retail Demand Response Programs by State (2023), Demonstrating Significant Regional Variations in Program Adoption



Customer enrollment is from 2023 and is based on surveyed data reported in EIA Form 861, including showing mostly retail demand response programs that may or may not be included in wholesale market programs. It shows that on average 6.5% of customers are enrolled nationwide, with significant regional variations.

Source: Energy Systems Integration Group; data from U.S. Energy Information Administration (U.S. EIA, 2024).

levels and the market structure and whether a customer is in a vertically integrated utility or wholesale market region.

### Critical Gaps and Proposed Solutions

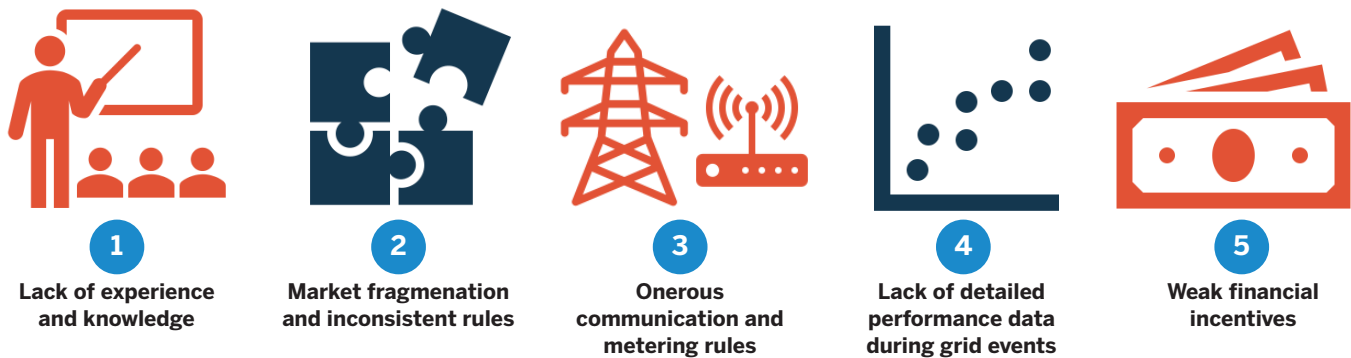
Our analysis identified five fundamental gaps limiting demand response participation in wholesale markets (Figure ES-3, p. xii), along with targeted solutions to address each challenge (Figure ES-4, p. xiv).

### **GAP 1. There is a lack of experience and knowledge about demand response technology and programs among system operators, state regulators, and consumers.**

The widespread lack of experience and knowledge about demand response technology and programs among system operators, state regulators, and consumers represents a fundamental barrier to adoption. This knowledge gap manifests across multiple areas: a lack of subject-matter experts, changing technology and effectiveness, inconsistent

FIGURE ES-3

### Five Gaps in Demand Response Participation in Wholesale Markets



Source: Energy Systems Integration Group.

definitions, lack of data around demand response participation, and low customer awareness. Feedback we received in our interviews with key stakeholders strongly suggests that when regions have knowledgeable and passionate champions—whether at the utility, system operator, or state regulator—this is directly linked to higher participation levels.

**Solutions:** To bridge this gap, regulators and system operators can identify dedicated subject-matter experts and establish working groups responsible for managing market design and demand response programs. These experts can then lead capacity-building workshops and educational programs to share best practices across regions. Additionally, load-serving entities can invest in simplified enrollment processes and easy-to-use platforms that provide customers with clear information about their energy use and potential benefits. Some regions have found success with opt-out rather than opt-in programs, automatically enrolling customers in dynamic pricing or demand response programs while retaining their ability to opt out entirely or for individual events.

#### **GAP 2. The demand response markets are limited by fragmentation and inconsistent rules.**

The demand response market today can be summarized as a tale of two options: loads functioning as supply-side resources in wholesale programs or load-modifying resources in retail programs. This dual-participation model, with each model operating under different rules and incentives, creates confusion and inadequate data on

current participation levels and characteristics. The study identified 16 different wholesale demand response programs across eight independent system operators, each with its own set of rules and regulations. This fragmentation makes it particularly challenging for aggregators to scale their operations, as they must customize their technological solutions for each program's specific requirements.

**Solutions:** To address this fragmentation, independent system operators need to work closely with their load-serving entities to clearly and transparently quantify and segment participation in wholesale and retail demand response programs by customer class and end use. Market designers can continue cooperative rulemaking that develops fair, stable, and competitive market structures. As one aggregator interviewed in this project emphasized, “one of the most important enablers for increased demand response participation is consistent and stable market rules, communications, and metering standards across wide areas.” Rather than pursuing perfect program rules, the focus should be on achieving consistency across jurisdictions to enable technology providers and aggregators to develop common products and business models.

#### **GAP 3. Communication and metering requirements can be onerous. Individual load resources do not need the granularity required of large-scale generation.**

Current metering and telemetry requirements pose excessive burdens, particularly for smaller or distributed resources. These requirements, originally designed for

large generation resources, worked well when demand response was primarily offered by large industrial customers. However, they now inhibit the participation of residential and small commercial customers, where much of the untapped potential lies. The cost for load-serving-entity-specified meters alone can be several hundred dollars per installation, plus additional wiring and labor requirements, making it economically unfeasible for many smaller participants to contribute to grid reliability as a demand response resource.

**Solutions:** Solutions to this challenge include allowing embedded measurement devices, such as inverters, to be used as end-use meters. In addition, independent system operators can implement statistical sampling approaches for aggregated resources rather than requiring direct measurement of each end-use load. They can evaluate aggregations of less-accurate metering technologies to measure demand curtailment and grid injections, as large groups of energy-metering devices may provide sufficient accuracy when aggregated. Additionally, minimum size requirements for aggregations should be modified to encourage residential participation, and nodal congestion pricing should be integrated into demand response settlements to allow aggregations across multiple locations to meet administrative sizing requirements.

**GAP 4: System operators lack detailed, publicly available information on demand response performance during emergency events, leading to inaccurate accreditation and eroding confidence in the resource.**

The absence of detailed, publicly available information on demand response performance during emergency events erodes confidence in the resource and complicates accurate accreditation. This was evident during Winter Storm Elliott in December 2022, when PJM’s demand response resources were awarded nearly \$90 million in positive compliance payments despite actual load reductions reaching only 26-32% of expected levels. This disconnect between compliance measurements and actual performance undermines confidence in demand response as a reliable resource.

Additionally, accreditation methodologies must be stable and predictable—sudden changes can lead to significant volatility in participation. For example, in PJM, recent



adjustments reduced the effective load-carrying capability for demand response from 100% to 76%, with projections suggesting further reductions to 50% by 2034/2035. This volatility in accreditation can create unnecessary risks for grid operators by undermining confidence in the resource.

**Solutions:** To address this gap, independent system operators can conduct detailed forensic reporting after every Energy Emergency Alert event, analyzing how demand response resources performed relative to their accredited capacity. These reports can be made publicly available to enhance transparency and build confidence.

**GAP 5: There are weak financial incentives, and even disincentives, for demand response at the wholesale market, load-serving entity, and consumer levels.**

Financial incentives for demand response participation remain too low to incent broad participation, particularly outside of capacity markets. While a low price does not indicate a market failure, low prices do create disincentives for load-serving entities and consumers to participate. Unlike other clean energy resources that benefit from federal tax incentives, state renewable portfolio standards, and long-term contracts, demand response is more exposed to short-term market conditions. Furthermore, load-serving entities can have financial disincentives to encourage demand response, as it reduces their ability to invest in new infrastructure and generate returns on

FIGURE ES-4

Framework for Implementing Solutions Across Five Key Areas

Experience and Knowledge	Program Boundaries and Rules	Communication and Metering	Performance and Accreditation	Financial Incentives and Retail Rates
Strengthen experience and knowledge in demand response technology and programs among system operators, state regulators, and consumers	Clarify demand response program boundaries across retail and wholesale programs and harmonize market rules across independent system operators	Refine communication and metering requirements to facilitate the integration of demand response into wholesale markets	Use detailed information on demand response performance during emergency events to improve accreditation and ensure reliability, while building confidence across stakeholders	Align financial incentives to stabilize revenues from long-term demand response contracts, incent load-serving entities to defer new capacity, and align customer rates

Source: Energy Systems Integration Group.

those investments. Customers, who by and large pay a flat volumetric rate for their electricity, have little incentive to adopt load-control technologies or behaviors in the first place.

**Solutions:** Solutions to these financial challenges include creating incentives for load-serving entities to enter into long-term contracts for demand response, similar to power purchase agreements for renewable energy. A “contracts for differences” approach could provide stable revenue streams over longer time horizons. Additionally, rate structures should enable value stacking, allowing demand response to provide multiple services across the grid, from generation capacity to transmission and distribution deferral. By coordinating retail rate design with demand response programs, load-serving entities can provide customers with both the motivation and the financial means to participate in load management. Finally, regulators can consider allowing demand response to participate as transmission and distribution assets, enabling access to long-term rate recovery mechanisms similar to transmission infrastructure.

Paths Forward

Implementing these solutions requires coordinated action across all levels of the energy supply chain, from federal and state regulators to system operators and market participants. The benefits of successful implementation include:

- **Faster integration** of demand response resources to keep pace with demand growth and plant retirements
- **A more diverse set of clean, emissions-free resources** providing alternatives to battery storage

Capturing the full flexibility potential of new technologies and load types like electric vehicles, heat pumps, behind-the-meter batteries, and data centers requires laying a strong foundation for demand response participation now.

and combustion turbines that are often used as new capacity resources

- Greater grid flexibility through **modular deployment** to scale up or down as grid needs evolve, without the risk of stranded assets
- Enhanced **consumer empowerment and engagement** providing them with financial incentives to adopt clean energy technologies such as electric vehicles, heat pumps, and energy-efficient appliances

The time for action is now. As traditional power plants retire and renewable resources increase, demand response technologies offer a flexible, fast-acting solution for balancing supply and demand. Unlike new generation, which takes years to develop, demand response can provide immediate support to the grid. Furthermore, as new technologies and load types like electric vehicles, heat pumps, behind-the-meter battery storage, and data centers are adopted, it is important to capture their full flexibility potential. This requires laying a strong foundation for demand response participation now, to ensure new loads are integrated well. Taking these steps will help unlock the full potential of demand response as a flexible, scalable, reliable resource in wholesale electricity markets.

# Introduction

**A**s the electricity grid transitions to accommodate more renewable energy and electrification, demand response plays a vital role in ensuring grid reliability and dampening price volatility in wholesale electricity markets. With traditional power plants retiring and renewable resources increasing, demand response technologies offer a flexible, fast-acting solution for balancing supply and demand, especially during peak demand periods.

Demand response has historically focused on load curtailments that are directly achieved through control of the end-use equipment during critical peak demand periods. While direct curtailable loads represent a core technology of demand response programs, this paper also explores the potential of other demand response

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**With traditional power plants retiring and renewable resources increasing, demand response technologies offer a flexible, fast-acting solution for balancing supply and demand, especially during peak demand periods.**

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technologies such as price-responsive demand, behind-the-meter generation, and distributed energy resource (DER) aggregations. Unlike new generation, which takes years to develop, demand response can provide immediate support to the grid by leveraging already-built infrastructure such as controllable industrial loads, advanced meters, and smart thermostats and appliances.



Other important benefits of demand response include its ability to bypass the interconnection queue, avoiding the delays that hinder new generation projects. Due to its modularity and flexibility, demand response can be deployed in a variety of sizes and technologies to meet changing grid needs. And demand response empowers consumers by providing financial incentives for reducing or shifting energy use, turning them into active participants in the clean energy transition.

However, while demand response has long been recognized as a flexible resource capable of managing electricity demand, particularly during peak load periods when generation may not be available, the actual deployment of demand response participation in wholesale electricity markets has stagnated or even declined in recent years. The objective of this report is to understand why, specifically in the wholesale market context.

## Demand Response Is One of Many Forms of Load Management

Demand response is one of many forms of load management and load flexibility, terms often used interchangeably across the industry. Unless otherwise noted, for the purposes of this report, **demand response** refers specifically to dispatchable load reductions (or load injections) that occur in response to a market signal—via either a price or a dispatch instruction received directly from the wholesale market, a utility, or a third-party aggregator. “Demand response” is not used here to describe indirect, or passive, reductions in load that arise due to behavioral change from time-varying prices or voluntary calls for conservation. It also does not refer, in this report, to energy efficiency or uncontrollable behind-the-meter generation (like rooftop solar) that reduce load throughout the year without direct control or discretion around the timing of load reductions.

The **participation model** for demand response resources can vary. **Retail demand response** programs are administered through a local load-serving entity (LSE) and may or may not interface directly with the wholesale market. **Wholesale demand response** resources are offered directly into the wholesale market as a supply-side resource, either individually or through a third-party aggregator. There is also an option to participate in both models via “**value-stacking**,” where a load can participate in both

retail and wholesale programs as long as the services are mutually exclusive and not double counted. While multiple participation models at the retail and wholesale levels provide flexibility for end-user demand response enrollment, they also create complexity and differences between the treatment of demand response across different wholesale markets and between retail and wholesale programs within a single market. This inconsistency makes it challenging for aggregators to scale programs and business models nationally.

Increasingly, demand response can also be a component of a **virtual power plant** that aggregates behind-the-meter generation, storage, and load flexibility to provide a wide range of grid services. These new resources enable both load curtailments and net injections to the grid (generation), and can aggregate across end uses, customer types, and schedules to provide a more holistic resource that provides energy, capacity, and ancillary services to the grid, analogous to a generating resource.

## The Demand Response Market Is Composed of Many Participants with Different Responsibilities

The demand response industry is made up of a variety of participants and stakeholders, with multiple participation models and paths for the resource to ultimately be provided into the market. While not exhaustive, Table 1 (p. 3) provides an overview of key players that are discussed throughout the report.

## Actual Participation of Demand Response in Wholesale Markets Is Lower Than Its Potential







Demand response has long been recognized as a flexible resource capable of managing electricity demand, particularly during peak load periods when generation may

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**Despite the potential of demand response to help manage electricity demand, its deployment in wholesale electricity markets has stagnated or even declined in recent years. The objective of this report is to understand why, and to outline solutions.**

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**TABLE 1**  
**Key Participants in Demand Response Programs**

	<p><b>End-use loads and devices</b> can be controlled remotely and include thermostats, water heaters, electric vehicles, lighting, and industrial processes.</p>
	<p><b>Technology providers</b> include hardware and software companies that enable the control and communication of end-use loads using information technology (IT) and Internet of Things (IoT) platforms. The technology can be directly embedded in the end-use device (i.e., smart thermostat) or incorporate an additional switch or control system (i.e., building management system) to control loads.</p>
	<p><b>End-use customers</b> include residential, commercial, and industrial customers that purchase electricity and can enroll in demand response programs in return for payment or incentive for participation. Options to enroll are directly with a third-party aggregator, with the utility, or (if large enough) directly with the wholesale market.</p>
	<p><b>Third-party aggregators</b> provide an option for end-use customers to participate in demand response programs outside of the conventional utility pathway. Aggregators bundle a portfolio of end-use customers into a single demand response resource offered in the market and/or utility program.</p>
	<p><b>Utilities, or load-serving entities,</b> are the electricity provider to end-use customers and can also serve as the administrator of retail demand response programs. The load-serving entities can either work with a third-party aggregator or aggregate resources themselves and choose whether to offer the portfolio into the wholesale market.</p>
	<p><b>Independent system operators</b> administer the wholesale power markets and coordinate across load-serving entities and third-party aggregators to settle both supply and demand of capacity, energy, and/or ancillary services.</p>
	<p><b>Regulators</b> are either state (public utility commission) or federal (Federal Energy Regulatory Commission) entities responsible for developing or approving rates and wholesale market tariffs that guide demand response participation rules.</p>

Source: Energy Systems Integration Group.

not be available. However, despite its promise, the actual deployment of demand response participation in wholesale electricity markets has stagnated or even declined in recent years. The objective of this report is to understand why, specifically in the wholesale market context. In this report, demand response participation refers to the inclusion of demand response in wholesale independent system operator (ISO) markets, whether the participation model is via retail demand response programs administered by an LSE—thus reducing energy consumption

and capacity needs indirectly—or by directly offering supply into the wholesale energy, capacity, and ancillary market as a market participant.

Our electric power grids are undergoing rapid transition away from fossil fuel resources and toward new wind, solar, and other renewable energy resources. Policymakers, regulators, and the investment community have, to date, focused on supply-side resources to support this energy transition. The supply-side push has included large

investments, tax credits, and regulations like state renewable portfolio standard requirements, to support new generation, storage, and transmission. As a result, the growth of these resources has been exponential.

### Demand Response Is a Flat, or Declining, Resource Despite Rapid Changes in the Industry

In contrast to fast-growing renewable and battery storage resources, demand response resources have seen little to no growth (Figure 1). Demand response has been largely flat—and even declining—over the past 10 years despite improvements in enabling technologies, communications, and controls. The reasons for this are manifold. Wind, solar, and battery storage all receive tax credits, incenting investments from large financial players, alongside state renewable portfolio standards and government-sponsored auctions and procurement mechanisms.

### Unrealized Potential Exists

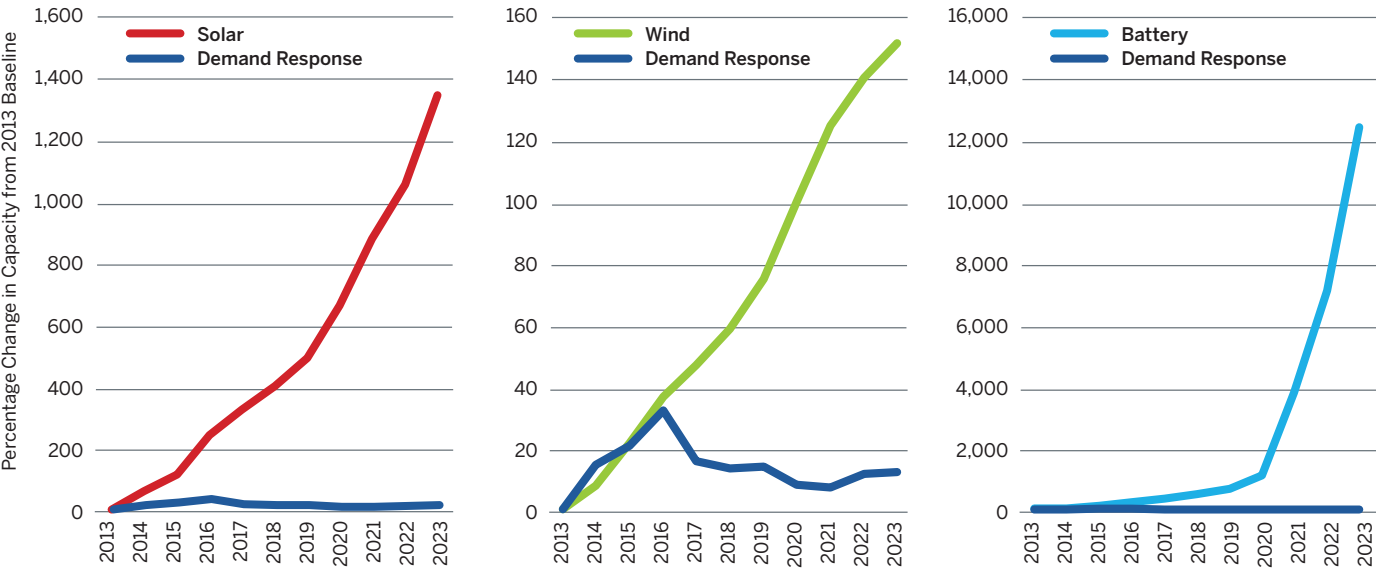
The potential benefits of demand response have only grown as LSEs and system operators face mounting

pressure from increasing electricity demand and the accelerated retirement of coal, gas, and nuclear plants. The recent shift in the electricity grid landscape has created a gap in demand response enrollment relative to its economic potential (Hledik et al., 2019) and relative to other clean energy resources. The impending retirement challenges, compounded with the need to meet environmental policy goals while ensuring system reliability, have raised industry-wide concerns over the next phase of demand response integration. In this shifting landscape, both load flexibility (generally) and demand response (specifically) need to be considered not only as tools for peak load management but also as potential contributions to ancillary services and energy arbitrage.

### Emerging Technologies Have the Potential to Grow Demand Response

Historically, most demand response programs were in the form of large, interruptible industrial and commercial loads. Where residential demand response was deployed, it was almost exclusively done through smart thermostat programs to control summer air conditioning demand, or, to a lesser extent, control water heaters. These residential

**FIGURE 1**  
U.S. Growth in Wind, Solar, and Battery Installed Capacity Relative to Demand Response



This figure shows the relative growth rates, measured as the percentage change from a 2013 baseline, for solar (left), wind (middle), and battery (right) relative to demand response shown in the dark blue line on each chart. Note that the y-axis changes for each chart, and the demand response line is consistent across all three.

Source: Energy Systems Integration Group; data from U.S. Energy Information Administration Forms 860 and 861 (2023).

applications are much more common at the retail level, directly being offered into utility-sponsored programs via integrated resource plans rather than through third-party aggregation in wholesale markets.

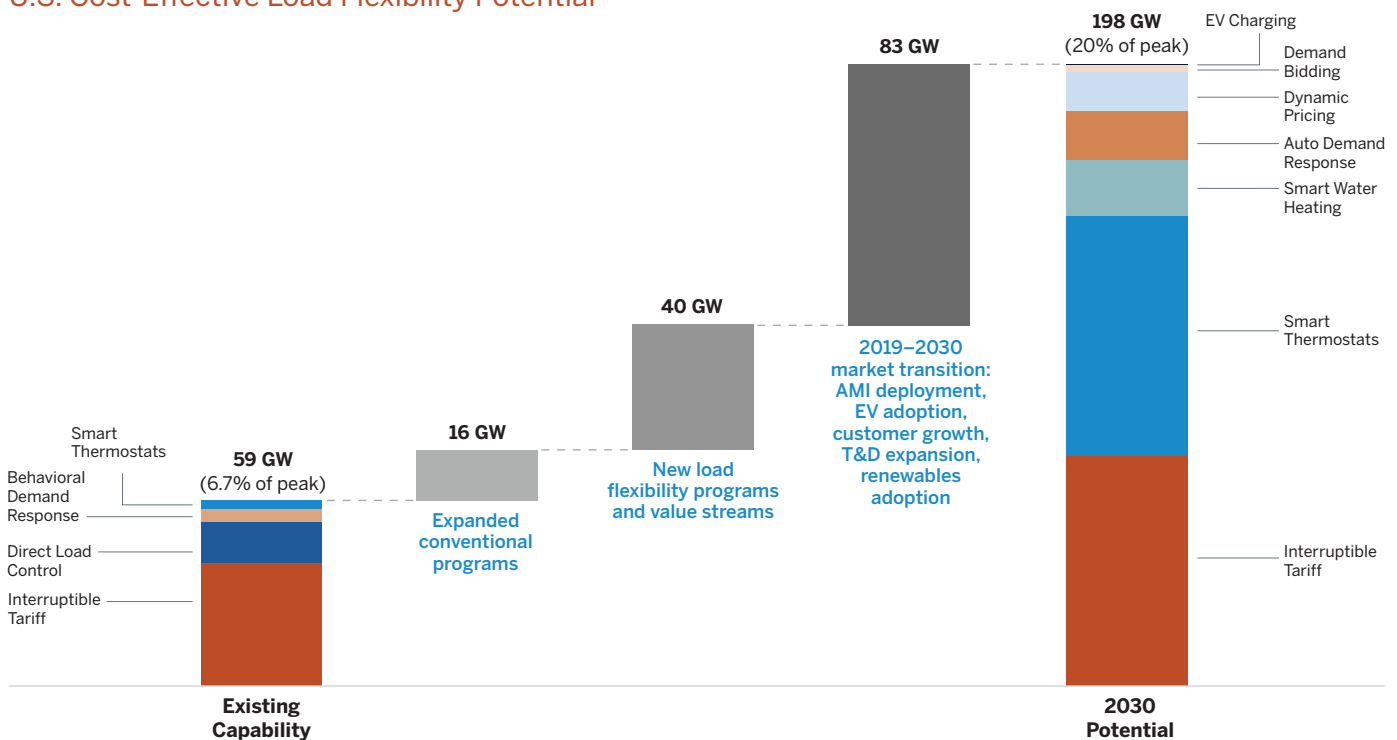
While these historical end uses will continue to be a focus, new sources of flexibility are arising due to electrification and advanced metering techniques. Growing electric vehicle demand, the adoption of heat pumps and electrified heating, and the continued adoption of behind-the-meter battery storage have the potential to

**Growing electric vehicle demand, adoption of heat pumps and electrified heating, and continued adoption of behind-the-meter battery storage have the potential to markedly increase the total potential of demand response.**

markedly increase the total potential of demand response. Each of these new interactive loads has built-in communication and control potential for LSEs and third-party aggregators.

According to the Brattle Group, these new technologies increase the total potential demand response market by over 70%, eventually meeting up to 20% of peak demand by 2030 (Hledik et al., 2019) (Figure 2). The future potential is spread across millions of residential and commercial customers, presenting an untapped industry with new opportunities for markets and regulation. While the focus of this report is to understand the challenge and limitations of current demand response participation, Figure 2 shows the importance of laying a good foundation now in order to capture new opportunities with further advanced metering infrastructure deployment, electric vehicle adoption, new customers, and new technologies.

**FIGURE 2**  
U.S. Cost-Effective Load Flexibility Potential



This figure shows existing and potential demand response segmented by end use (interruptible tariff, smart thermostats, smart water heating, auto demand response, dynamic pricing, and demand bidding). Intermediate steps show how that potential can be enabled, including through expansion of existing programs, new load flexibility, and new opportunities from electric vehicle adoption, advanced metering infrastructure deployment, and transmission needs.

Source: Hledik et al. (2019).

## Tale of Two Competing Participation Models

Even as demand response studies and utility pilot programs explore the increasing potential of demand response programs, the current reality paints a much different picture. As of 2023, demand response comprised less than 7% of peak load<sup>1</sup>—showing little to no growth from previous years (FERC, 2023) and only 6.5% participation levels for individual customers in retail programs (U.S. EIA, 2024). This gap between potential and actual demand response participation underscores the need for coordinated action across all levels of the energy supply chain, bringing targeted feedback from demand response practitioners to the desks of wholesale market designers and their regulators. Key barriers exist that prevent demand response from realizing its full value in wholesale electricity markets, and overcoming these obstacles will be critical to unlocking its broad adoption.

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**The gap between potential and actual demand response participation underscores the need for coordinated action across all levels of the energy supply chain, bringing targeted feedback from demand response practitioners to the desks of wholesale market designers and their regulators.**

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While the gaps and challenges around demand response exist across different market structures, this report focuses on demand response in wholesale ISO markets, highlighting the importance of both programs administered by the LSE and programs offered by third-party aggregators that are active in the ISO market. Programs considered under an LSE will be labeled as “retail” in this report and include demand response resources directly enrolled in an LSE-administered program, which typically offsets the LSE’s capacity obligation in the wholesale market. While this type of program may follow dispatch signals or pricing that is aligned with wholesale rates, it is really a load modifier and not directly offered into the market as a supply-side resource or compensated based

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**This report identifies specific gaps preventing the widespread integration of demand response in wholesale markets, offering actionable solutions designed to bridge these gaps.**

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on wholesale prices. An alternative participation model, denoted in this report as “wholesale,” is directly offering into the wholesale market outside of LSE administration, often through a third-party aggregator and serving as an independent entity similar to a generator. Both participation models represent options for demand response participation in wholesale electricity markets, yet the two models often operate separately despite offering a common product.

This report identifies specific gaps preventing the widespread integration of demand response in wholesale markets, offering actionable solutions designed to bridge these gaps. To better understand these gaps, this study leveraged in-depth interviews with demand response experts across the industry, including system operators, regulators, aggregators, and consumers. The industry interviews also provided a direct platform for demand response practitioners to provide potential solutions to the stagnated demand response market.

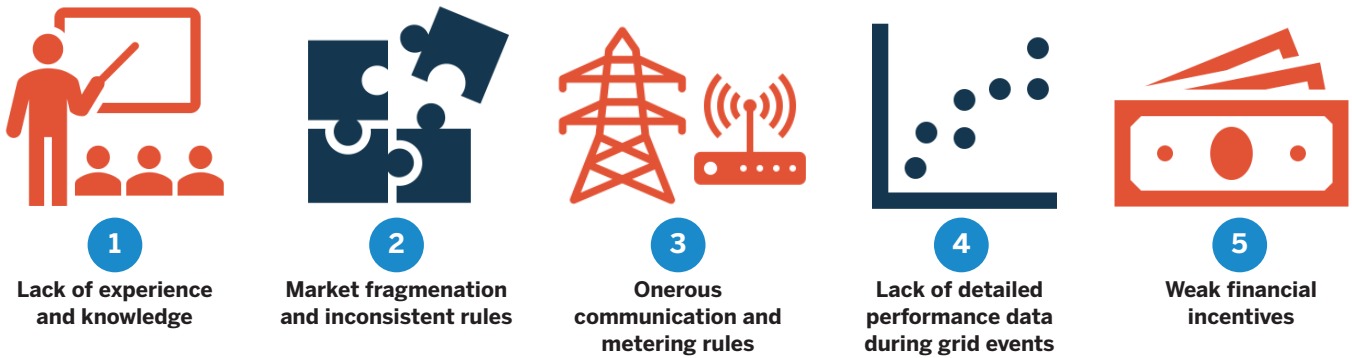
## Gaps in Demand Response Participation Need to Be Bridged to Accelerate Deployment

While demand response has proven capabilities in reducing peak load and enhancing grid flexibility (U.S. DOE, 2023), its deployment remains constrained across market designs, regulatory frameworks, and operational integration. In our interviews with key stakeholders, five key gaps, shown in Figure 3 (p. 7), stand out as major barriers to the widespread adoption of demand response and must be bridged to accelerate its deployment and integration across the energy ecosystem.

1 Demand response is often measured as an amount of load that is enrolled in a demand response program and is available at times of peak demand to curtail (or generate) when called upon. In this report it is often expressed as a percentage of peak demand to allow for direct comparison across ISOs.

FIGURE 3

Five Gaps in Demand Response Participation in Wholesale Markets



Source: Energy Systems Integration Group.

**GAP 1. There is a lack of experience and knowledge about demand response technology and programs among system operators, state regulators, and consumers.**

Despite advancements in demand response technologies, many stakeholders—including system operators, regulators, and consumers—lack a comprehensive understanding of how demand response can be effectively and reliably integrated into the energy system. In contrast, feedback we received in our interviews with key stakeholders strongly suggests that when regions have knowledgeable and passionate champions—whether at the utility, ISO, or state regulator—this is directly linked to higher participation levels. The knowledge gap that more typically prevails prevents the full utilization of demand response resources even with longstanding technologies and options. This knowledge gap is compounded when the novelty of newer technologies like heat pumps, electric vehicles, and behind-the-meter storage is introduced. To close this gap requires education and capacity-building—including transparent and accurate data availability, lessons shared from pilot programs, and easier-to-follow and stable tariff structures—to ensure that stakeholders are equipped to deploy demand response effectively.

**GAP 2. The demand response markets are limited by fragmentation and inconsistent rules.**

The demand response market is currently fragmented, with varying program designs and inconsistent rules across different ISOs and LSEs. This lack of uniformity

creates confusion for market participants and makes it difficult for aggregators to scale demand response programs. Standardization across regions and clearer guidelines for both retail and wholesale programs are essential to reduce complexity and encourage broader participation.

**GAP 3. Communication and metering requirements can be onerous. Individual load resources do not need the granularity required of large-scale generation.**

Another substantial challenge lies in the operational difficulties of communicating with and metering demand response resources. Stringent metering and telemetry requirements often pose excessive burdens, particularly for smaller or distributed resources. These requirements



are often designed around large generation resources, and they worked well when most demand response was offered by large industrial customers. However, they can inhibit the participation of residential and small commercial customers, where much of the untapped potential for demand response lies. While proponents of stringent metering and communications claim these are necessary if the resource is going to be relied on to provide capacity services, statistical sampling provides an accurate alternative. Detailed measured response of individual loads may not be needed provided that robust statistical sampling methods can compare smaller groups of demand response–enrolled customers against control groups of customers that are not enrolled in demand response programs. This approach would not require direct metering and analysis of all demand response customers while still providing accurate baselining.

**GAP 4: System operators lack detailed, publicly available information on demand response performance during emergency events, leading to inaccurate accreditation and eroding confidence in the resource.**

Accurate baselining and performance tracking during emergency events remains a challenge in building confidence in demand response programs. Without reliable data on how demand response performs during system stress, system operators struggle to confidently integrate it into their resource adequacy planning and do not have the requisite information to model the resource



accurately in their resource adequacy assessments. Improving data collection, performance metrics, and accreditation processes will ensure that demand response can be counted on as a dependable resource during critical grid events and build confidence across stakeholder groups.

**GAP 5: There are weak financial incentives, and even disincentives, for demand response at the wholesale market, load-serving entity, and consumer levels.**

Financial incentives for demand response participation remain too low to incent broad participation, particularly outside of capacity markets. While a low price does not indicate a market failure, low prices do create disincentives for LSEs and consumers to participate. This stems from the misalignment of rate structures and market rules, and the fact that LSEs do not receive a rate of return on demand response expenses like they do for capital projects. It will be crucial to strengthen financial mechanisms, including stable revenue streams for demand response participation in wholesale electricity markets, to encourage wider adoption. While unstable revenues are a challenge for other resource types, demand response is disproportionately reliant on capacity markets and does not benefit from long-term power purchase agreements, tax incentives, or renewable portfolio standard programs offered to other clean energy resources.

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It is important to note that many of these gaps are not new. For over a decade, issues such as fragmented markets, onerous interconnection requirements, and the lack of transparent performance data have persisted, continually challenging demand response aggregators and ISOs tasked with market administration.

Progress has been made in addressing some of these barriers, sometimes incrementally and other times more significantly. Some of this progress has come from FERC directives, while in other cases, advances have been achieved through stakeholder processes and collaborative market redesigns. The purpose of this report is to clearly articulate these enduring gaps and present actionable solutions for moving forward. By doing so, the report aims to provide ISO market designers, regulators, and policymakers with a roadmap for improving demand response integration.



## Bridging Demand Response Gaps Offers Several Benefits

One of the key benefits of bridging the above gaps is the **faster integration of resources**. Utility-scale generation projects often take years to plan, site, construct, and interconnect, which can leave regions vulnerable during capacity crunches, such as the spike in PJM's 2024 capacity auction price due to tightening supply conditions. In contrast, demand response can be deployed more quickly, as it does not rely on new infrastructure or transmission upgrades to connect, providing critical capacity in a short time frame. This ability to rapidly scale resources makes demand response a valuable asset in addressing short-term reliability issues without waiting for new generation to come online.

Bridging these gaps would also enable **a more diverse set of clean, emissions-free resources** to participate in the grid. By expanding demand response, system operators can avoid over-reliance on any single resource type, thus reducing bottlenecks in supply chains and deployment timelines for utility-scale projects like wind, solar, or batteries. Diversity in the resource mix also helps to reduce risk and ensures a more resilient energy system.

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The modularity and flexibility of demand response make it an ideal resource for a rapidly changing grid. Demand response resources can be scaled up or down as grid needs evolve, without the risk of stranded assets that can occur with large, centralized generation projects.

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Additionally, the **modularity and flexibility** of demand response make it an ideal resource for a rapidly changing grid. Demand response resources can be scaled up or down as grid needs evolve, without the risk of stranded assets that can occur with large, centralized generation projects. This right-sizing of resources allows for more efficient grid management and reduces financial risk for investors and LSEs.

Finally, bridging these gaps can **empower consumers** by providing them with financial incentives to adopt clean energy technologies such as electric vehicles, heat pumps, and energy-efficient appliances. Through demand response programs, consumers can directly participate in grid reliability efforts and be compensated for providing load flexibility while contributing to the broader goal of decarbonization.

# Current Market Performance and Trends

## Measuring Market Participation for Demand Response Nationwide

This section provides an overview of demand response participation, in aggregate, across the United States, including both ISO markets and within vertically integrated utilities. While this gives an overview of the demand response landscape, the focus of this report is specifically related to participation in the wholesale ISO construct, discussed in the section that follows.

Trends of demand response capacity available in wholesale markets—measured as the amount of enrolled, available response during times of peak load—are tracked by several industry-wide entities, including FERC, the North American Electric Reliability Corporation (NERC), and the U.S. Energy Information Administration (EIA). Unlike a generator’s installed capacity, which is a known quantity, demand response capacity is less specific. It is typically an estimate of a demand response portfolio’s aggregate capacity when called on for a given hour and often estimated only during peak load conditions. However, not all demand response resources will be available during those conditions—for example, if temperatures are low and air conditioners are not operating at full output—or they may vary by time of day depending on the end use. Due to these variations in performance, demand response capacity is not consistently reported across entities or data sources.

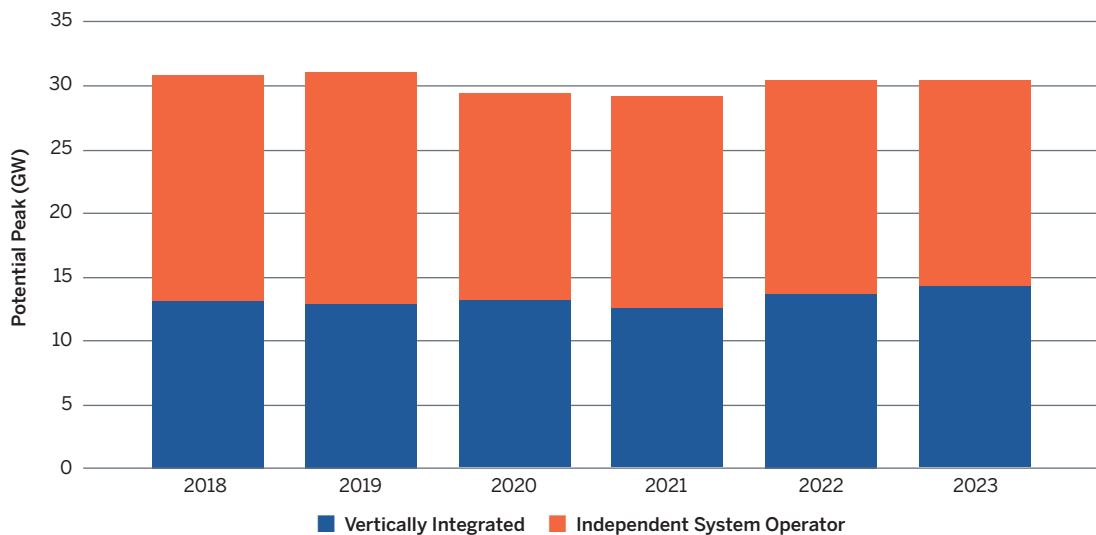
While not exhaustive, the data collections shown in this report represent general industry trends derived from these public data sources. In addition to these large-scale data sources, regional system operators also provide information on their regional demand-response capacity; however, these reports often lack uniformity. For example, the Independent System Operator for New England (ISO-NE) reports individual demand-response resource capacities for both passive and active demand response.<sup>2</sup> In ISO-NE, passive resources represent non-dispatchable, behind-the-meter resources that make permanent load reductions, while active resources are dispatched based on wholesale market conditions and operator actions. But while descriptive, the specific resource definitions provided by ISO-NE exist only in New England’s demand response market. Other ISOs may provide aggregate demand-response capacity enrolled in specific ISO programs, but without identifying the type of each individual resource. Given the disparity of reporting, it is difficult, if not impossible, to get accurate data about demand response across multiple data sources and multiple ISO regions. This highlights a significant data and information challenge both within and between ISOs.

Data from EIA Form 861, shown in Figure 4 (p. 11), illustrate the stagnant growth of demand response resources in the U.S. This dataset represents survey data collected from distribution utilities and power marketers across the U.S., inclusive of LSEs in wholesale ISOs and vertically integrated utilities.<sup>3</sup> The figure shows potential

<sup>2</sup> <https://www.iso-ne.com/markets-operations/market-performance/performance-reports>

<sup>3</sup> Given that EIA Form 861 data are provided by some but not all wholesale market participants, wholesale demand response programs are not fully represented; therefore, comparisons across data sources, for example, between EIA Form 861 and ISO data, are not feasible or recommended.

**FIGURE 4**  
**Potential Peak Demand Savings from Demand Response Enrollment**



This figure shows the potential peak demand savings reported through EIA Form 861 showing mostly retail demand response programs. Each bar is segmented by whether the demand response is within a wholesale ISO or in a vertically integrated utility. These data show that across both wholesale markets and regulated utilities, demand response deployment has been flat or declining over the past decade despite growing load.

Source: Energy Systems Integration Group; data from U.S. Energy Information Administration (U.S. EIA, 2024).

peak demand savings reported through EIA Form 861.<sup>4</sup> Each bar is segmented by whether the demand response is within a wholesale ISO or in a vertically integrated utility. These data show that regardless of LSE jurisdiction, demand response deployment has been flat or declining over the past decade.

Across all LSEs, both within ISOs programs and within retail LSEs, peak demand savings did not exhibit expansion from 2017 to 2022. Roughly half of potential peak savings lie in the jurisdictions of ISOs, showing no clear separation between the two market structures. Over the course of the reporting period, potential peak savings was just above 31,000 MW for U.S. retail demand response programs.

Analysis of demand response program participation, derived from EIA Form 861 data, highlights notable regional variation across the United States. This dataset captures participation across residential, commercial, and

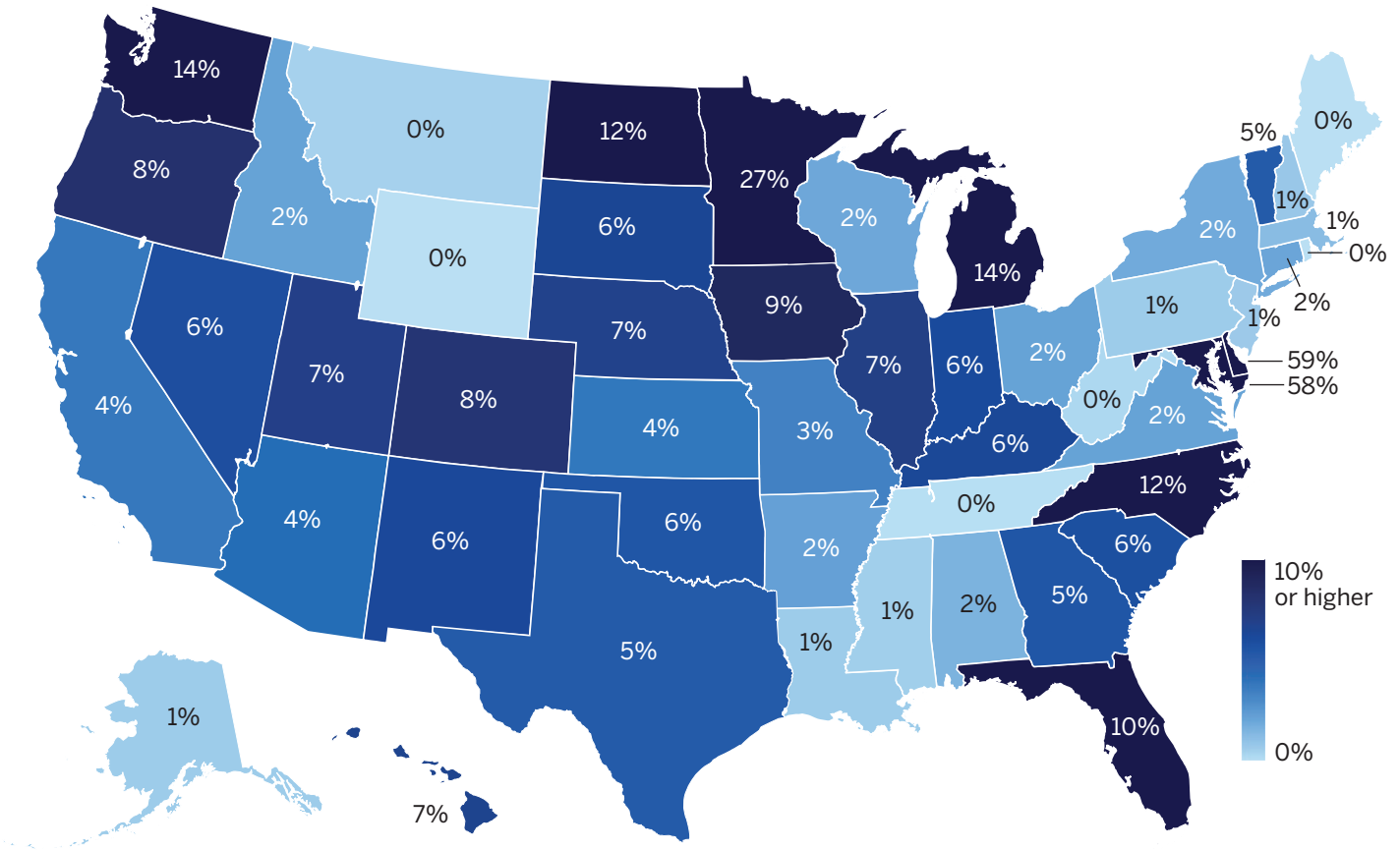
industrial customer classes, focusing primarily—but not exclusively—on retail demand response. Some programs, particularly those operating at the wholesale level, are not fully reflected in these data, underscoring the lack of consistent reporting for demand response at a national level.

As seen in Figure 5 (p. 12), participation levels across states show enrollment rates ranging between 2% and 8%, with an average of 6.5% nationwide. This figure indicates significant untapped potential for demand response to further contribute to grid flexibility and capacity needs. Interestingly, there appears to be little correlation between participation levels and the market structure and whether a customer is in a vertically integrated utility or wholesale market regions. In fact, if any trend emerges, it is that participation rates tend to be higher in states where programs are administered primarily at the retail level.

<sup>4</sup> According to EIA Form 861 data, “potential peak demand savings” are calculated as the total demand savings that could occur at the time of system peak hour, assuming all demand response is called. “Actual peak demand savings” represents the amount of the potential demand reduction that was actually called upon and utilized during the year.

FIGURE 5

Percentage of Customers Enrolled in Retail Demand Response Programs by State, 2023



Customer enrollment is from 2023 and is based on surveyed data reported in EIA Form 861, including showing mostly retail demand response programs that may or may not be included in wholesale market programs. It shows that on average 6.5% of customers are enrolled nationwide, with significant regional variations.

Source: Energy Systems Integration Group; data from U.S. Energy Information Administration (U.S. EIA, 2024).

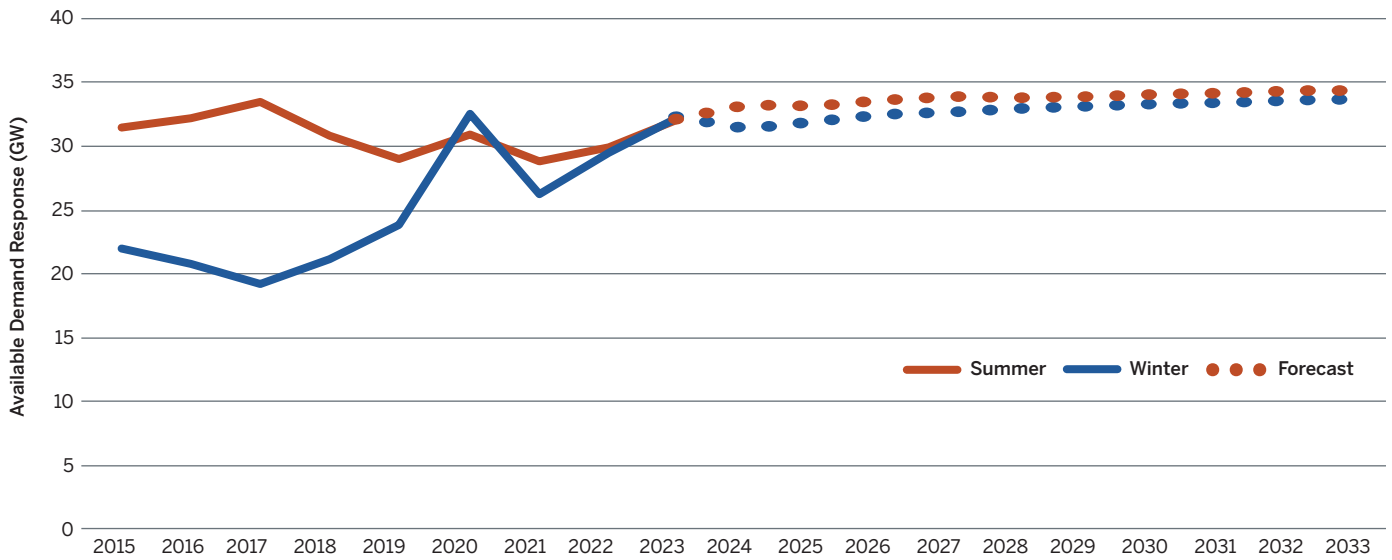
The leading states for demand response participation include Delaware (59%), Maryland (58%), Minnesota (27%), Washington (14%), Michigan (14%), North Carolina (12%), North Dakota (12%), and Florida (10%) where over 10% of customers are enrolled in programs (U.S. EIA, 2024). These states demonstrate that robust participation can be achieved under diverse market structures and regulatory environments. However, even in these leading states, most customers remain outside of demand response programs, highlighting substantial opportunities to expand enrollment.

Projecting forward, the NERC Long-Term Reliability Assessment aggregates data submitted from each of North America’s LSEs via the Electric Reliability Organization (ERO) Regional Entities, including projections

of load and demand response. While generally focused on long-term reliability, the NERC Long-Term Reliability Assessment—and the accompanying Electricity Supply and Demand Database—gathers demand reductions expected from dispatchable and controllable demand response programs in its baseline assumptions forecasted across 10 years. Total demand response capacity for all regions and seasons assumed in the 2023 NERC Long-Term Reliability Assessment are shown in Figure 6 (p. 13). While the previous two figures provided historical demand response adoption rates, this shows that LSEs and ISOs across North America—which submit their forecasts to NERC—have limited expectations for future demand response adoption, despite increases in electric vehicles, heat pumps, and behind-the-meter storage.

**FIGURE 6**

**Projected Total and Available Demand-Response Capacity in North America, by Season**



Total demand response capacity is shown for all regions and seasons assumed in the 2023 NERC Long-Term Reliability Assessment. This shows that load-serving entities across North America—which submit their forecasts to NERC—have limited expectations for future demand response adoption, despite increases in electric vehicles, heat pumps, and behind-the-meter storage.

Source: Energy Systems Integration Group; data from NERC Electricity Supply and Demand Database (NERC, 2024).



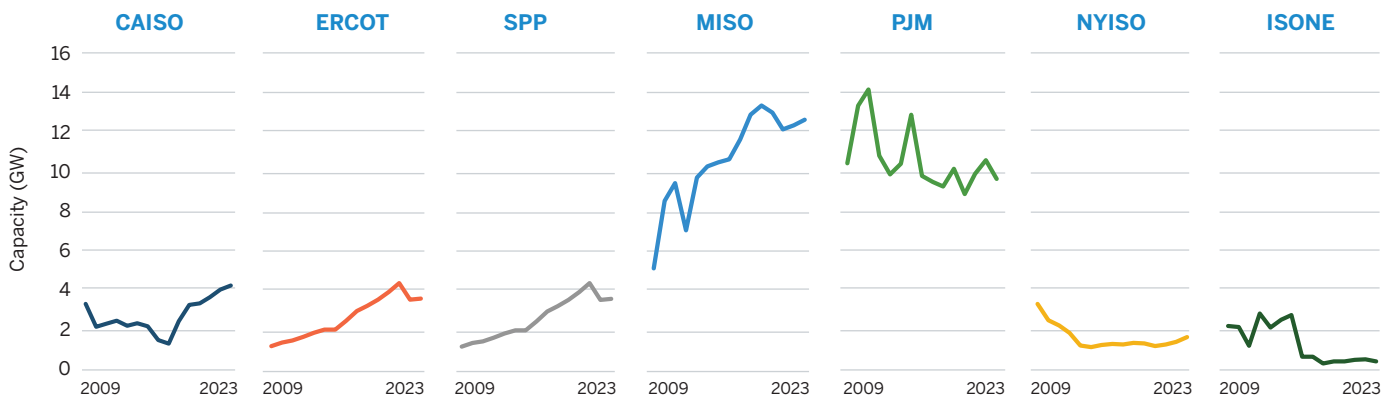
## Demand Response at the ISOs

To best isolate demand response participation in wholesale ISO markets, this study used the FERC *Assessment of Demand Response and Advanced Metering*. Through a variety of ISO data sources, FERC collects the total amount of wholesale demand response capacity and compares ISOs by normalizing the capacity as a percentage of each region's peak demand (shown in Figure 7).

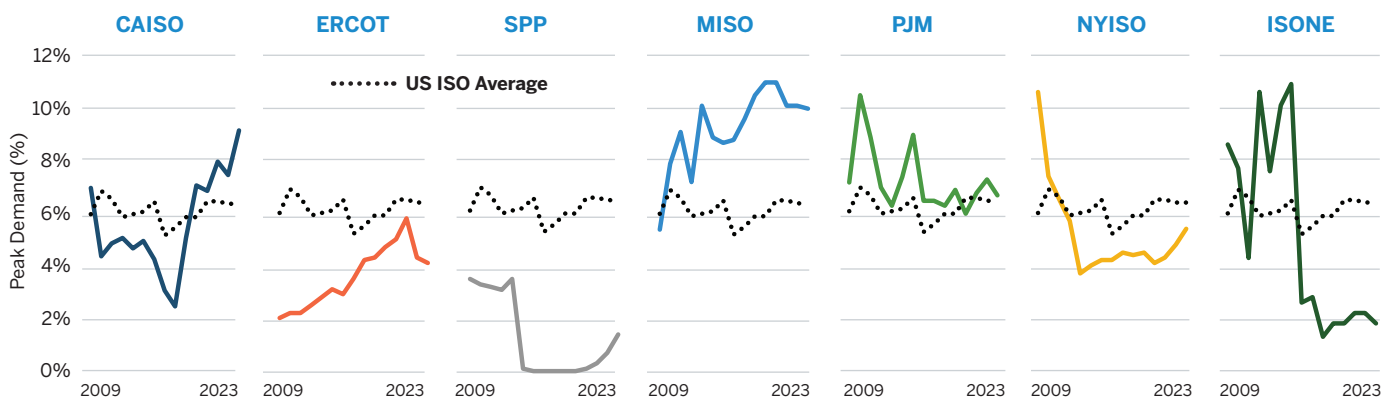
Since 2009, average peak demand met by demand response capacity in the wholesale market has remained constant at around 6%. But Figure 7 also shows variation across regions and variation over time, with regions showing both large increases and decreases from year to year (FERC, 2023). While the comparative analysis alone is informative, it also warrants additional context:

- Collectively, the PJM and Midcontinent Independent System Operator (MISO) markets have the most demand response enrolled and account for 70% of the nation's wholesale demand response participation. This is not a surprise as they are the largest of the ISOs by a considerable margin.
- Only two regional entities, ISO-NE and MISO, have surpassed a 10% benchmark in peak demand over the reporting period, with MISO reporting the highest percentage of demand response capacity at 11%. In both cases, the demand response participation can come from both retail LSE programs offered into the wholesale market and direct participation as a third-party entity.
- While ISO-NE showed early growth, demand response participation dropped precipitously from 2016 to 2018

**FIGURE 7A**  
Wholesale Demand Response Capacity by ISO in GW



**FIGURE 7B**  
Wholesale Demand Response Capacity by ISO as a Percentage of Peak Demand



Source: Energy Systems Integration Group; data from the Federal Energy Regulatory Commission's 2023 *Assessment of Demand Response and Advanced Metering* (FERC, 2023).

with the introduction of a more administratively burdensome Price Responsive Demand program and the Pay-for-Performance program, which increased financial risks to demand response providers.

- Similarly, PJM was an early leader in demand response in 2015, but changes to seasonal accreditation, pay for performance, and accreditation reforms led to decreased participation over time.
- In contrast, the California Independent System Operator (CAISO) has shown growth in demand response since 2018 when the California Public Utilities Commission developed programs to implement demand response at the three investor-owned utilities in the state, providing an additional funding and incentive structure for participation in the wholesale market.
- The Southwest Power Pool (SPP) had no enrollment in demand response for several years as 16 states across the central and Midwest United States implemented “opt out” clauses following the issuing of FERC Order 719, effectively excluding demand response participation in the wholesale markets and only implementing demand response at the retail level (Forrester, 2022).

Regardless of the region, it is clear from Figure 7 (p. 14) that at the wholesale level, demand response capacity has shown relatively flat growth overall, with year-to-year variability driven by capacity market rules and price volatility.

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**Participation models vary based on resource type and the services provided, such as energy, capacity, or ancillary services. The goal of these models is to integrate diverse resources into the market while maintaining fairness, transparency, and reliability in grid operations.**

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### **Demand Response Participation Models at ISOs**

When interfacing directly with a wholesale ISO market, demand response resources must select a participation model. An ISO participation model defines the framework and set of rules that determine how resources (including generation, demand response, and DERs) participate in wholesale electricity markets. This model specifies the requirements for registration, metering, accreditation, bidding, and performance of resources, ensuring that they comply with market rules.

Participation models vary based on resource type and the services provided, such as energy, capacity, or ancillary services. For demand response, an ISO participation model typically governs how demand-side resources bid into markets as supply-side resources, reduce load in response to market signals, and receive compensation for their contributions. The goal of these models is to integrate diverse resources into the market while maintaining fairness, transparency, and reliability in grid operations.



**TABLE 2**  
**ISO Demand Response Program Quantities, 2021–2023**

ISO	Program Name	2021 Quantity (MW)	2022 Quantity (MW)	2023 Quantity (MW)
CAISO	Utility Demand Response	1,499	1,459	1,348
	Supply Plan Demand Response	262	417	333
ERCOT	Non-Controllable Load Resources	3,795	3,610	3,435
	Controllable Load Resources	>100	>600	607
IESO	Hourly Demand Response Resource	808	923	955
ISO-NE	Active Demand Capacity Resource	511	466	438
	Passive Demand Resource	3,423	3,610	3,360
MISO	Load Modifying Resources	11,220	11,712	11,829
	Demand Response Resources	350	430	508
	Emergency Demand Response	627	119	331
NYISO	Special Case Resources	1,168	1,231	1,282
	Emergency Demand Response	2	3	12
	Day-Ahead Demand Response Program	0	0	0
PJM	Load Management	8,833	9,074	8,203
	Economic Demand Response	2,015	2,636	3,007
SPP	Demand Response Program	176	362	793

Note: This table shows only programs that are offered into the ISO market and may not include retail programs administered by LSEs to reduce their peak loads and capacity obligation. See Gap 2 for more discussion.

Source: Energy Systems Integration Group; data sources given in the report's [online appendix](#).

Since the issuing of FERC Order 745 in 2011 and FERC Order 2222 in 2020, ISOs have individually developed demand response programs to compensate for load curtailment similar to generation resources. FERC Order 745 recognized demand response as an alternative to generation and required ISOs to compensate these resources at the market-based rate at their point of interconnection. FERC Order 2222 enabled DERs, such as rooftop solar, energy storage, and electric vehicles, to participate in wholesale electricity markets by aggregating their capacity, energy, and services into a singular demand response resource (FERC, 2024). Both FERC orders were well received by demand response aggregators and advocates, spurring optimistic outlooks for future growth in the resource. However, FERC

Order 2222 has not yet been fully implemented by ISOs (NARUC, 2024).

Participation models for demand response programs have become more complex and heterogeneous across the country. This study identified 16 wholesale demand response programs under the jurisdiction of eight ISOs. A comparison matrix was created and is located in the online appendix,<sup>5</sup> containing megawatt quantities, definitions, and characteristics for each of the 16 programs. Three years of program quantities for each program are shown in Table 2.

The expansion rates for wholesale demand response programs across North America vary considerably from

5 For more information comparing ISO demand response programs, see the online appendix available at <https://www.esig.energy/demand-response-in-wholesale-markets>.

region to region and often program to program. In many regions, an upward trend in one program's capacity is met with a downward trend in another. While diverging capacity trends may not be causally related, the lack of

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**The disparate and complex sets of participation models and market rules both within a market and across markets make it challenging for aggregators to create business models because there is no consistent set of rules.**

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consistent demand-response capacity growth across and within ISOs demonstrates a lack of industry momentum to grow wholesale demand response programs at the same pace seen by renewable generation.

While recent FERC orders were intended to develop minimum guidelines for demand response participation models and create some consistency across the ISOs, there remains a disparate and complex set of participation models and market rules both within a market and across markets. This lack of uniformity makes it challenging for aggregators to create business models because there is no consistent set of rules. For example, an Active Demand Capacity Resource in ISO-NE and a Special Case Resource in the New York Independent System Operator (NYISO) provide similar capacity services in each region and would be called on—in practice—similarly between the two regions. However, a demand response resource in each region will face an entirely different set of energy market requirements after installation. A New England Active Demand Capacity Resource is required to maintain and submit hourly energy market offers during every hour of a demand response resource's year-long capacity obligation, while a New York Special Case Resource submits a strike price to NYISO only once during resource registration. The two programs are geographically separated by only a state border, yet the day-to-day management of the demand response resource in each region varies considerably.

### **Lack of Industry Momentum**

The next phase of demand response lies in the aggregation of individual DER components, highlighted in the filing



of FERC Order 2222. Although the FERC Order was filed in 2020, implementation of DER aggregations will take several years, with most ISOs estimating implementation between 2026 and 2027 or later (FERC, 2024). As a result, Order 2222 has yet to reach substantial implementation across regional grid operators. Response filings can be categorized as complicated and cryptic, often met with FERC criticism for not meeting the original order's intent or requirements. Demand response aggregators have seen success in small-scale utility programs, yet these pilot programs have yet to make the jump to the wholesale level without proper Order 2222 implementation (NARUC, 2024).

Recognizing these limitations, this study—via in-depth interviews with industry stakeholders—identified five gaps in demand response participation in wholesale markets. These gaps, elaborated on in the following section, present the key challenges facing demand response participation in wholesale markets today. Recommendations are then offered to resolve the gaps and help facilitate reliable, cost-effective demand response in wholesale markets.

# Gaps in Demand Response Participation in Wholesale Markets

In-depth interviews with industry stakeholders led to our identification of the following five gaps limiting demand response participation in wholesale markets today.

**Gap 1: There is a lack of experience and knowledge about demand response technology and programs among system operators, state regulators, and consumers.**

Many interviewees in this study noted a lack of knowledge across the industry about the capabilities and effectiveness of demand response as a resource. This knowledge gap can be organized across five reasons: (1) a lack of subject-matter experts, (2) changing technology and effectiveness, (3) inconsistent definitions, (4) lack of data around demand response participation, and (5) low customer awareness.

## Five Elements of the Knowledge Gap

### Lack of Subject-Matter Experts

Throughout our interviews of stakeholders in the demand response space, it became clear that there is disparate individual experience across markets, particularly at the ISOs and regulators. In some cases, there is a dedicated lead for demand response programs at an ISO, or there is a subject-matter expert at an individual state utility commission that champions the technology. One interviewee said, “one of the big differentiators of whether there is strong adoption of demand response at an LSE or within an ISO comes down to an individual or small group that drives the initiative.” In other cases, some ISOs had no clear leader of demand response programs, and many state regulators have limited bandwidth to build expertise in a relatively narrow topic.

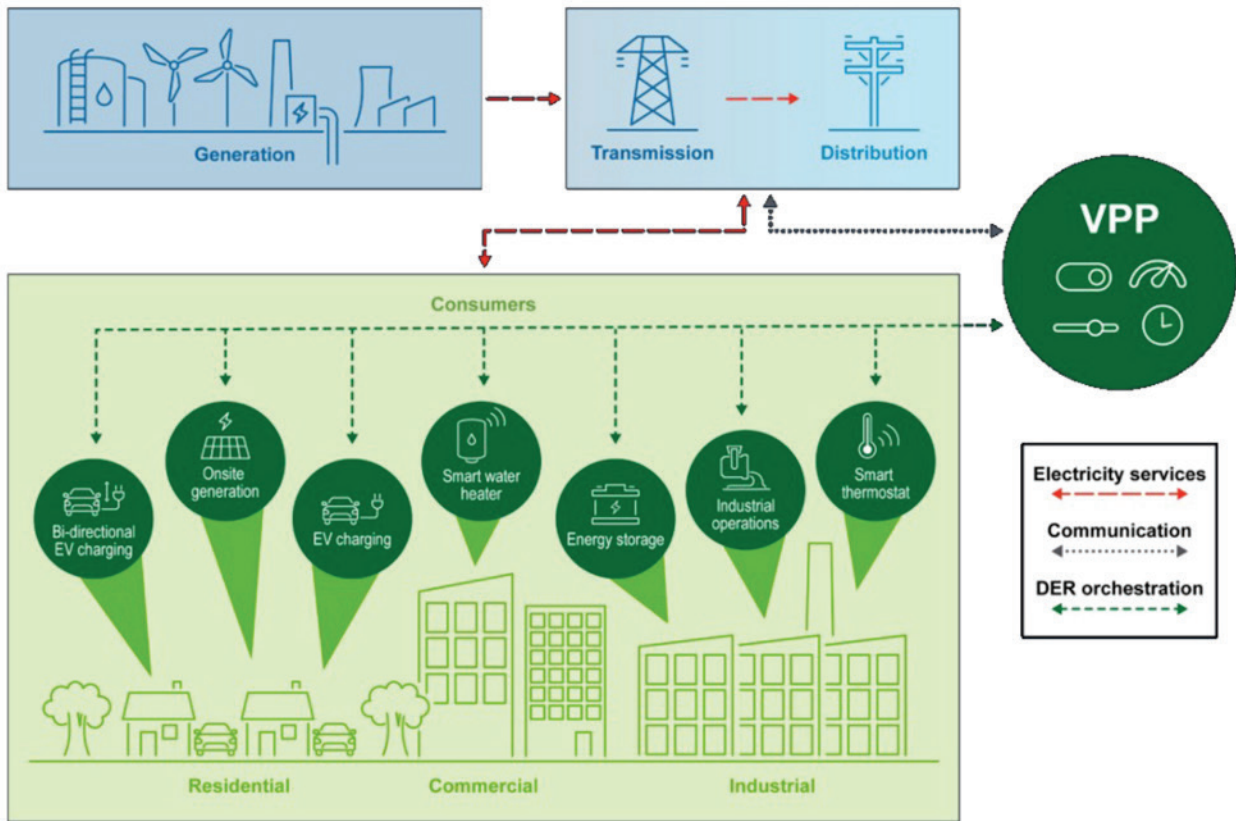
### Changing Technology and Effectiveness

The past 10 years have seen advances in the technology embedded in end-use loads like smart thermostats, electric vehicles, and behind-the-meter storage. However, there is still, at times, a preconceived notion that demand response (particularly at the residential level) cannot be effective because it cannot be measured or observed. One interviewee said that “in the early 2000s we implemented an air conditioning program that wirelessly turned off AC units, but people simply covered the receiver and collected the payment. It was hard to know what we were getting from the program.” But advances in the Internet of Things and communication technology have largely solved this problem. Still, there is only limited publicly available data showing the effectiveness of demand response during reliability events, particularly from pilot programs and for emerging technologies.

### Inconsistent Definitions

Changing terminology is also a challenge for increasing participation in demand response programs. A virtual power plant is often discussed as the newest entrant in DER aggregations, yet the term is not well understood industry-wide. To many who were interviewed, a virtual power plant was simply a new name for old technology, believing that operators of such a resource may not be adding any additional value to the grid outside of a traditional curtailable load. Others’ understanding was more nuanced, explaining that virtual power plants were a newer form of aggregation, combining load and generation control behind the meter to curtail consumption and/or increase generation at end-use customers (Figure 8, p. 19). For the purposes of this study, no distinction between virtual power plants and DERs is made. Instead, these are distributed resources that can provide demand response, among other grid services, alongside other

**FIGURE 8**  
**Role of a Virtual Power Plant in the Wholesale Energy Market**



A virtual power plant is a newer form of aggregation, combining load and generation control behind the meter to curtail consumption and/or increase generation at end-use customers. The aggregated resource can provide demand response, among other grid services and use cases.

Source: Pathways to Virtual Power Plants Commercial Liftoff (U.S. DOE, 2023).

controllable loads used in conventional demand response programs.

The legacy approach of direct load curtailments should be replaced and improved to reflect the newer capabilities of load management. Colloquially referred to as a virtual power plant, these new resources enable both load curtailments and net injections to the grid (generation) and can aggregate across end uses, customer types, and schedules to provide a more holistic resource that provides energy, capacity, and ancillary services to the grid, analogous to a generating resource.

As an example of regulatory action, the California Energy Commission recognized the technological differences of demand response technologies by offering three different

enrollment tracks under its new Demand Side Grid Support program: non-combustion resources, demand response aggregators, and storage virtual power plants. Each track targets groups of consumers that would not typically be captured in the existing demand response framework, with the storage virtual power plant demonstrating the most participation in the 2024 program season (CEC, 2024).

### Lack of Data

The knowledge gap is also exacerbated by a lack of data. First and foremost, this includes unclear and inconsistent reporting of existing demand response participation. As discussed in the previous section, there are programs administered directly at the ISO with third-party



participation, as well as retail program participation with an LSE. The latter is tracked by EIA Form 861 for each responding LSE (U.S. EIA, 2024). However, sometimes retail demand response is offered into the wholesale market, and other times it is not. Conversely, the ISOs will often publish data on demand response offered into the market, which will include both third-party aggregators directly offering into the market and retail programs rolling up from LSEs. The absence of delineation between the two sources can lead to significant double counting in data reporting.

There is also a lack of data around load segmentation by customer, location, and temporal profiles. Data can now be collected via advanced metering infrastructure on an individual customer basis, across time and location. However, making these (anonymized) data available to aggregators and other market participation is challenging due to data security, confidentiality, and information technology concerns. As a result, most LSEs have yet to administer wide-scale residential demand response programs using the data made available by advanced metering. The infrastructure to enable dynamic residential participation in demand response exists, with nearly 70% of U.S. residential customers hooked up to an advanced metering system as of 2021 (FERC, 2023). According to one interviewee, “residential customers represent the largest sector of untapped demand response potential, yet participation in these programs has not been well represented at the wholesale level.”

### Low Customer Awareness

Even with the infrastructure in place, residential customers are often unaware of demand response programs or time-varying rates and likely do not know the potential benefits. Furthermore, customers are often required to opt in to residential demand response programs rather than be automatically enrolled. The administrative burden of filling out paperwork or navigating through LSE websites may outweigh the unclear and marginal rate benefits for many customers. If LSEs were to automatically enroll customers into programs such as time-of-use rates or smart appliance management, the aggregated benefits could more easily be realized, and the individual administrative burdens to customers could be avoided. Proper implementation of an opt-out program relies on perfect information provided to customers on how their energy consumption is being affected along with how their energy rates are being administered.

### Recommendations for Gap 1

This report offers three recommendations to ISOs and their state and FERC regulators to incent future demand response participation.

#### Have a Dedicated Subject-Matter Expert and Working Group to Manage the Market Design and Demand Response Programs

Each ISO and regulator can have a dedicated subject-matter expert and working group responsible for managing

the market design and wholesale demand response programs. The working group would interact both internally and externally with program stakeholders to create a regulatory framework that expands alongside demand response technology.

### **Establish Demand Response Capacity-Building and Education Programs to Share Best Practices**

Demand response capacity-building and education programs can be established to share best practices across wholesale markets. By collaborating across regions, ISOs and LSEs can learn to overcome technical, regulatory, and economic hurdles with foresight. Programs such as capacity-building workshops or industry-wide demand response meetings can help clear up confusion on demand response capabilities and better leverage the unique abilities offered by aggregators.

### **Implement Pilot and Demonstration Projects**

Pilot and demonstration projects can provide useful data and examples of the effectiveness of demand response programs, especially for new technologies like electric vehicles and behind-the-meter storage. But care should be taken to avoid one-off programs. One demand response aggregator said they have experienced “death by a thousand pilots,” where each pilot requires a significant effort to set up unique software and reporting but without a clear opportunity to scale. A pilot program should have a clear path to the implementation of a full-scale participation model if it is successful.

In addition to clarifying demand response at the regulatory level, a few improvements at the end-use customer level can expand the investment landscape for demand response participation:

- LSEs can consider opt-out provisions rather than elective, opt-in participation in future customer demand response and dynamic pricing programs. It will improve participation to have all customers automatically enrolled in dynamic pricing or demand response programs, while retaining the ability to opt out of the program entirely or during individual events. This would bypass the customer knowledge gap about how to enroll but would require care in implementing to ensure fairness.

- LSEs would do well to invest in simplified enrollment processes, easy-to-use platforms, and monitoring tools to give customers information about their hourly energy use and how their load curtailment or grid injections can translate into system reliability.

## **Gap 2: The demand response markets are limited by fragmentation and inconsistent rules.**

### **The Tale of Two Options: Creation of a Fragmented Market and Potential for Conflict and Confusion Through the Existence of Both Wholesale and Retail Programs**

Demand response participation today can be summarized as a tale of two options: loads functioning as supply-side resources in wholesale programs or load-modifying resources in retail programs. These two participation models—each operating under different rules and incentives—often compete for the same demand response capacity, leading to inefficiencies in resource deployment. By instead combining the two participation models into one framework, a direct connection can be made between demand response customers and the grid-level outcomes of their actions. Integrating all demand response into a uniform program—while retaining both retail and wholesale participation options—can increase market opportunities and data visibility to LSEs, aggregators, and wholesale regulators alike.

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### **Integrating all demand response into a uniform program—while retaining both retail and wholesale participation options—can increase market opportunities and data visibility to LSEs, aggregators, and wholesale regulators alike.**

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**Wholesale programs** that are administered by ISOs offer demand response as a supply-side resource, functioning similarly to generation resources in competitive markets—often as part of capacity auctions or specialized load-management programs.<sup>6</sup> In this example, the aggregated demand-side resources are offered into the market as a

<sup>6</sup> See the [online appendix](#) for an overview of wholesale programs.

bundle. In the capacity market this would show up as a bundled resource with an offer of capacity at a specific price. In energy markets this would include offers of megawatts at specific prices that can vary over time. In either case, the pooled resources are seen by the market in a similar manner to a supply-side generator. These programs allow demand response aggregators or individual loads to bid directly into the market, competing with traditional generation resources to provide system capacity, energy, and ancillary services.

**Retail programs** are administered directly by the LSEs and target end users with the goal of reducing peak demand. While these are retail programs, they are still participating in the broader ISO framework, either by directly being offered into the wholesale market as a supply-side resource by the LSE or indirectly as reduced load obligations that the LSE has to cover in the capacity market. These programs are designed to modify load in ways that reduce an LSE’s capacity obligations in wholesale markets, often by adjusting customer demand during periods of peak demand. LSEs use these retail programs to reduce the overall load forecast and ensure they meet their capacity and resource adequacy requirements.

Both types of programs aim to use flexible load to meet grid needs, but there is often no clear or coherent reporting between the two. The overlap rather than integration of the two programs creates confusion for participants, increases administrative burdens, and risks double counting of demand response resources. Many technology providers and aggregators interviewed for this project agreed that the lack of coordination between wholesale and retail programs limits the scalability of demand response. At the same time, ISO staff interviewed also expressed concern that the coexistence of wholesale and retail demand response programs presents significant challenges, especially if it is not clear to the wholesale system operator how or where retail programs are offered into the market.

**Benefits of Wholesale Demand Response Programs**

Wholesale demand response programs offer several advantages over their retail counterparts, particularly in terms of **scalability**. These programs operate under a consistent set of rules across wide areas, ensuring that demand response resources can be aggregated and treated uniformly and making it easier to develop large, stable



markets. ISOs offer a **competitive marketplace** where anyone can participate, providing demand response aggregators the same opportunity to compete as any other supply-side resource. This competitive environment reduces the need to rely on potentially slower-moving LSE-administered programs and eliminates potential disincentives that LSEs may have to self-build their own resources at the expense of demand response.

Another key benefit of wholesale participation is the ability to directly measure and compare demand response against traditional generation resources, placing them on an **equitable playing field**. This transparency ensures that demand response is treated fairly in terms of resource adequacy planning and performance evaluation. Additionally, wholesale demand response is more closely tied to bulk system needs, making it an effective resource for addressing system-wide challenges, such as peak demand periods or emergency events.

### Limitations of Wholesale Demand Response Programs

Wholesale programs also have limitations. One significant drawback is the **volatility of capacity markets**, which can make it hard for aggregators to build stable business models and customer enrollment. This is especially true because wholesale demand response revenues are disproportionately generated from capacity market revenues. This lack of financial stability can make it difficult for demand response aggregators to build long-term business models, especially when compared to the more stable pricing structures found in retail programs.

Additionally, **value stacking across end uses**—the ability to capture benefits across generation, transmission, and distribution systems—is often more difficult in wholesale market programs. Wholesale programs primarily focus on system-wide benefits, but local distribution grid needs, such as deferring transmission and distribution upgrades, are often overlooked. Without the ability to combine demand response grid services provided at both the transmission and distribution system levels, some of the potential financial benefits of demand response remain untapped. However, ISO program administrators need to ensure that there is not double compensation for the same service—like peak load reduction compensated by both retail and



wholesale programs—and that providing a service in one program type does not inhibit a resource from providing it in the other.

**Uniformity** is also a requirement for electricity markets, but it often requires many different demand response technologies to fit unfairly within a uniform mold. Markets are constructed to trade among homogenous products, but demand response resources are often heterogenous in size, capability, duration, and seasonality—even more so than traditional generation. Capacity markets, for example, are designed to trade firm, or effective, capacity across resource types. This fungibility allows the market to trade combustion turbine capacity with battery storage, albeit at different rates (capacity credits). This accreditation can be extended to demand response resources, but specifics matter. For example, PJM requires year-round capacity from demand response rather than allowing seasonal participation. This requires demand response resources to be able to match the full load requirement in both summer and winter. Flexible cooling demand of course has no availability in the winter, thus requiring demand response providers to aggregate across multiple loads and locations in order to participate in the market.

Finally, participating in wholesale markets currently requires significant **expertise and resources** (discussed in Gap 1), which are out of reach for most small loads and could be simplified. The complexity of individual load

enrollment in wholesale markets is a reason why retail programs continue even in wholesale markets, as the utility has existing relationships, metering, and billing in place with its customers. However, it is increasingly becoming an option for commercial and residential loads to participate in power markets as advanced metering and other smart infrastructure advances. But participation currently requires loads to navigate complex market rules and compliance requirements, which can be burdensome for smaller participants. While third-party aggregators can help mitigate this challenge, the barrier to entry is currently high for many, and the additional aggregation dilutes financial incentives as it distributes them across more entities.

### Benefits of Retail Demand Response Programs

Retail demand response programs, on the other hand, offer more **direct relationships between LSEs and end users**, allowing for greater customization and flexibility. LSEs can develop programs that align with retail rates, ensuring that customers' financial incentives are tied to their actual energy use. This structure makes it easier for customers to understand and participate in demand response programs, particularly through mechanisms like time-of-use rates or critical peak pricing.

Retail programs also allow for **value stacking**, particularly by combining the benefits of demand response across generation, transmission, and distribution systems. LSEs can design programs that simultaneously reduce peak demand, defer infrastructure upgrades, and manage local grid reliability. This comprehensive approach can ensure that demand response resources are fully utilized, even if they do not meet the more rigid requirements of wholesale markets.

### Limitations of Retail Demand Response Programs

However, retail programs also have significant limitations. The **lack of competition** was cited as a major concern throughout the interviews conducted, as demand response resources are typically procured by a single buyer, often the LSE itself. This can lead to less competitive pricing and fewer incentives for innovation compared to the open competition found in wholesale markets. To be successful, retail demand response options are reliant

on an assertive and knowledgeable regulator to ensure the market remains efficient and mitigate the monopsony power of its LSEs.

Additionally, the rules around accreditation, metering, and telemetry are often **specific to each LSE**, creating a patchwork of requirements that makes it difficult to scale demand response across multiple regions or markets. As a result, aggregators, technology companies, and demand response providers must develop costly custom products for each LSE.

Retail programs are also limited by their **local focus**. While these programs may help reduce peak demand for a specific LSE, their benefits to the larger bulk power system are less direct or may be unclear. This is especially true if the LSE's load profile is not coincident with the ISO's system-wide peak or the capacity is sited in a location that is less beneficial for the bulk system. This design can reduce the overall effectiveness of demand response as a grid resource. Ideally, however, even local retail programs would be offered in the wholesale market so bulk-system and local reliability needs can be mitigated together.

In summary, the fragmentation of demand response across retail and wholesale programs can create conflict and confusion for participants. While there are intentional benefits of having two participation models, there needs to be a clear delineation between the two and accounting to ensure resources are not double counted. Both within and across each wholesale participation method, consistency is crucial in order to create a scalable market.

### Lack of Wholesale Consistency: Myriad Market Programs, Changing Rules, and a Lack of Standards Resulting in a Market That Lacks Uniformity and Scale

In addition to fragmenting the demand response customer base, significant variation in demand response programs splits and slows down the adoption of current wholesale programs. See Table 2 (p. 16) for a listing of the 16 different wholesale demand response programs with 16 different sets of rules and regulations that were identified among 8 different ISOs.<sup>7</sup>

7 Further details about the 16 wholesale demand response programs are shown in the [online appendix](#).

## Different Rules in Different Jurisdictions

Throughout our interviews, the most consistent challenge raised by aggregators was how difficult it can be to design a custom technological solution to the various demand response programs. One aggregator specified how most of its demand response portfolio resided under one ISO’s jurisdiction, not due to economic feasibility or favorable market rules but because of the large size of the jurisdiction. They described how they “like that market simply because it represents the largest available market with a consistent set of rules and regulations across a wide area.”

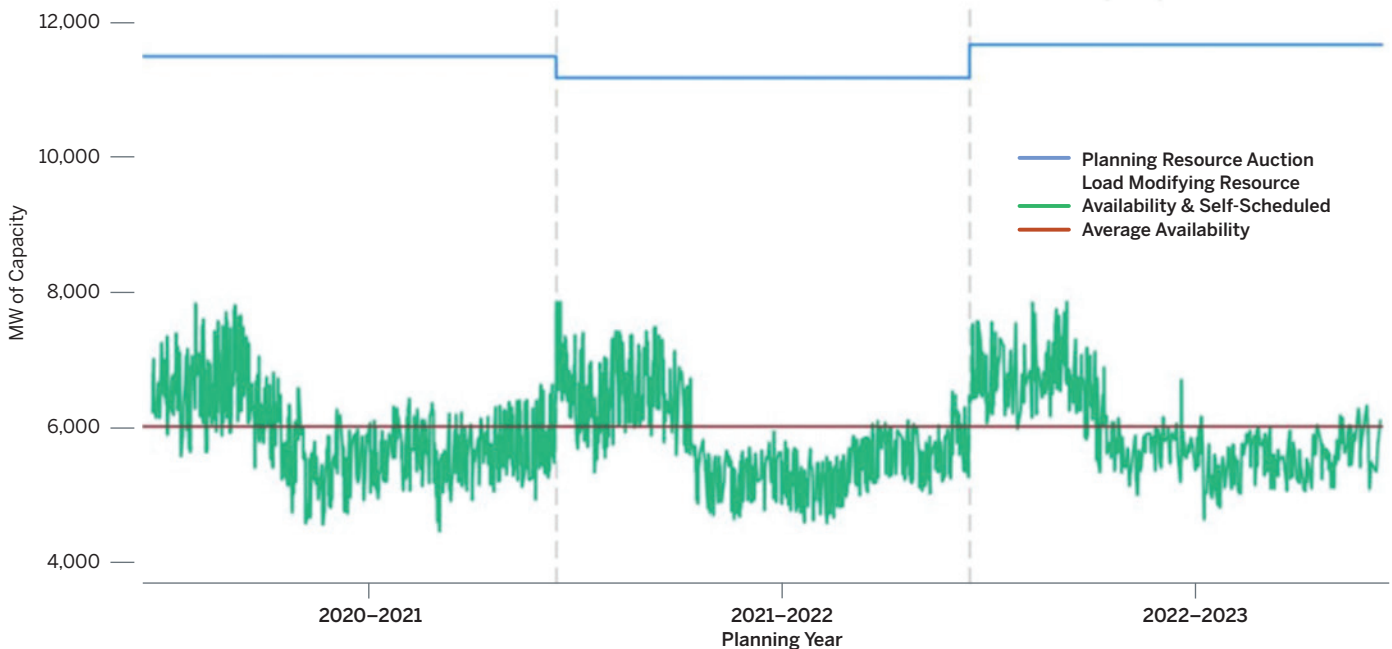
## Sudden Rule Changes in a Single Jurisdiction

Not only do rules and regulations vary considerably across jurisdictions, but rules under one jurisdiction can change suddenly and drastically, seriously affecting the feasibility of demand response participation year to year. Many ISOs are currently changing accreditation methods and enforcing stricter performance guidelines for demand

response resources enrolled in capacity markets. While updated accreditation is appropriate, there is a concern among demand response aggregators that these new accreditation rules go beyond the expectations of traditional generation technologies and the accreditation may not be consistently applied across resource types.

A recent example of tightened demand response regulations occurred in April 2024 when MISO introduced new reforms for its Load Modifying Resources (LMRs), largely in response to low historical real-time LMR availability. The new reforms require all LMRs to respond to MISO operator calls in 30 minutes or less and to follow a new performance penalty structure that can permanently disqualify an LMR from future capacity auctions if it performs poorly during MISO’s energy emergency events. Figure 9 shows a comparison of contracted LMR capacity (blue line) and available LMR capacity (green line) that was shared in an April 2024 MISO stakeholder presentation.

**FIGURE 9**  
Comparison of Cleared Load Modifying Resources and Their Real-Time Availability Reported to MISO



This chart shows MISO’s Load Modifying Resources offered into market (green line) relative to the total capacity enrolled in the program to meet capacity needs (blue line). This highlights the significant gap between the available resource in real time versus what is used in long-term planning.

Note: Intermittent behind-the-meter generation excluded.

Source: Courtesy of the Midcontinent Independent System Operator (MISO, 2024).



MISO's tightening of its program participation rules was prompted by LMR availability being well below procured capacity in the three planning years shown. While the new reforms may address the availability issues, they come at the cost of reduced demand response capacity: as of April 2024, only 935 MW (around 20%) of LMRs were capable of meeting MISO's new accreditation requirements. Over the first few years of implementation, even more participants could drop out if faced with the prospect of non-performance penalties.

## Recommendations for Gap 2

### Clarify, Then Integrate Wholesale and Retail Programs

ISO market designers need to work closely with their LSEs to clearly and transparently count wholesale and retail demand response programs. This reporting consistency should also be reflected by the EIA (Form 861) and in FERC's yearly *Assessment of Demand Response and Advanced Metering* reports (FERC, 2023).

### Focus on Cooperative Rulemaking

Market design changes at ISOs are often made through a committee consisting of a broad group of stakeholders with voting rights, but information disparities between ISOs and stakeholders can make the changes feel one-sided. Market designers need to continue working closely with their demand response providers to develop a fair, stable, and competitive market structure for demand response that operates in tandem with the rest of the wholesale energy market.

## Strive for Consistency, Not for Perfection

The single most important enabler for increased demand response participation is consistent and stable market rules, communications, and metering requirements across wide areas. ISOs can strive to make participation rules consistent across one another and only develop unique requirements if there is a clear rationale to do so. This would allow technology providers and aggregators to develop common products and business models across markets.

**Gap 3: Communication and metering requirements can be onerous. Individual load resources do not need the granularity required of large-scale generation.**

## Sizing and Locational Requirements

In many ISOs today, high minimum size requirements for demand response resources limit their participation in wholesale markets. Wholesale demand response resources are offered into the market similar to a generator in many cases, so the ISO typically requires a minimum size for individual or aggregated resources. This is due in part to the administrative burden of tracking many small resources, but is also for metering and verification purposes. Additionally, there is a computational consideration limiting the amount of unique resources offered into the security-constrained unit commitment and dispatch. For these reasons, an ISO may want to prevent too many small resources from participating as separate entities, instead requiring third-party aggregators or LSEs to bring a larger portfolio that is offered jointly to the market.

Size thresholds are implemented in one of two ways: (1) on the minimum aggregation size of resources that can be collectively offered into the market, or (2) on the minimum size of any individual resource within the aggregation. Minimum size requirements by ISO programs are provided in the [online appendix](#). Today, most programs have a minimum aggregation size of 100 kW and an individual resource size of 10 kW, but only after FERC orders requiring ISOs to, in many cases, lower their requirements to these levels.

These thresholds are most impactful at the residential level, where relatively small loads—either at the household

level or individual end use (e.g., an electric vehicle)—may not meet the size requirements. The average household has an average electricity demand of 2 kW and on-peak demand of around 5 kW. A 10 kW minimum requirement for individual resources would thus exclude basically all residential demand response participation, even if aggregated.

In an effort to standardize demand response sizing requirements, FERC Order 2222 requires ISOs to set a minimum size of DER aggregations (including but not limited to resources providing demand response) of no more than 100 kW but is silent on minimum size requirements for individual participants. This is currently a contested issue in many FERC compliance filings. Reaching 100 kW DER aggregations can be a challenge, especially when considering the locational requirements imposed by ISOs. If pricing nodes are small and geographically dispersed, reaching 100 kW of enrolled load can be a challenge. Furthermore, many ISOs do not provide locations of individual loads (or addresses) that map to aggregation points, leaving aggregators guessing on where and how to aggregate end users.

## Recommendations for Sizing/ Locational Requirements

### Modify the Minimum Size of Aggregations

While size requirements are reasonable in order to limit the administrative burden of running a wholesale market, ISOs should not significantly limit residential demand response due to an administratively set value, especially at the individual resource level. While minimum aggregation size may be required for administrative purposes, excluding aggregated residential loads, electric vehicle chargers, or other smaller end uses misses opportunities made possible by current technologies. Regulators and aggregators need to explore different sizing options that encourage all levels of demand response participation at the wholesale level.

### Integrate Nodal Congestion Pricing into Demand Response Settlements

By leveraging location-based pricing methods, ISOs need to allow demand response aggregations to be settled across multiple locations to meet administrative sizing requirements. By doing so, aggregators and LSEs would

be able to package bulk demand response aggregations without the hassle and administrative burden of splitting by locations if technologically infeasible.

## Metering Requirements

To participate in demand response programs, many ISO markets have specific requirements for the metering (often referred to as “revenue grade metering”) at the load, and any distributed generation (solar photovoltaic or storage) resource. Based on feedback from demand response suppliers and aggregators during the interviews conducted, this significantly increases costs for both equipment and installation—the cost for the LSE-specified meter alone can be a few hundred dollars, plus additional wiring and labor requirements. It also increases the complexity of software controls for end-use technologies.

Opponents of these metering rules argue that many of these technologies—like a behind-the-meter storage resource or electric vehicle, for example—can already measure consumption and generation with the inverter and software embedded in the end-use device. They say that while the accuracy may not meet typical specifications for LSE billing, when aggregated across tens of thousands of devices, the demand response portfolio can be accurately measured without additional metering requirements. Recently, the California Public Utilities Commission allowed submetering of electric vehicles using the electric vehicle supply equipment meter directly (CPUC, 2022). However, because of measurement accuracy and data integrity concerns, current wholesale rules do not allow this technical solution and impose the more expensive metering requirements on third-party demand response aggregators.

While some market participants favor loosening these metering rules, many of the operators defend them. According to some of the system operators interviewed, many say that real-time metering and telemetry is required in order to ensure that the demand response resources are available and will respond to dispatch signals when called on. They argue that if the resources are to be treated as a supply-side resource like a generator, they should have similar characteristics on observability and control at the individual asset level.

Lastly, there are important implications for metering requirements on aggregated resources like virtual power plants that can curtail loads or provide negative injections into the grid across a wide range of end uses and technologies. To balance the metering of multiple demand response sources, LSEs and aggregators can strive to build platforms to manage all end uses under a single platform or via robust interoperability between platforms—as opposed to disparate platforms for thermostat, electric vehicles, and building management systems.

To overcome these metering challenges, many proponents favor statistical sampling of aggregated resources rather than direct measurement and visibility into each end-use load. This is discussed further in the following section.

## Recommendations for Metering Requirements

### Consider Aggregations of Meters

ISOs can implement pilots to study aggregations of less accurate metering technologies to measure demand curtailment and grid injections. Large groups of energy-metering devices, such as inverters, may be able to provide an unbiased and accurate-enough measurement.

### Standardize Metering Requirements

ISOs can coordinate intraregionally and interregionally to develop a consistent metering method that can apply across all demand response technology types. Ensuring consistency across metering methods, communication, and data storage across regions can encourage widespread investment into appropriate metering technologies and software to support them.

### Ensure/Implement Interoperability Between Platforms

ISOs, LSEs, and aggregators can strive to build platforms to manage all end uses under a single architecture with robust interoperability between platforms—as opposed to disparate platforms for individual end uses, such as separate software solutions for thermostat, electric vehicles, and building management systems.

## Sampling and Baseline Requirements

To properly measure the reliability contribution of demand response, the expected amount of load—the baseline—for a participant must be accurately calculated. As of today, many questions remain about how to properly



baseline the many different technologies that can comprise a demand response resource. This baselining ultimately determines payments when the resource is dispatched and the accreditation it receives for the capacity it offers into the market.

Inaccurate baselining ultimately can lead to further barriers to demand response participation in wholesale markets. If demand response is over-counted, then ISOs will lose confidence in the resource, penalize underperformance, and try to restrict additional resources entering the system. If demand response is under-counted due to inaccurate baselining—thus underestimating the response actually received—then the financial incentives for customers may not be sufficient to attract participation into demand response programs.

### Common Baselining Approaches

A common approach among ISOs is to measure a demand response resource's energy consumption across historical days with common seasonality patterns. An example would be to measure a customer's average consumption during a summer weekday to compare to its demand reduction during a similar day, both seasonally and in terms of temperature, when the grid operator requests a load curtailment (either during a grid Energy Emergency Alert event or during a test). However, while this approach can individually baseline each demand response resource in a jurisdiction, the simplistic calculation can suffer from participant gaming and improper accreditation. It is also data-intensive, requiring a

comparison of sub-hourly consumption data at each participating load. And it does not easily integrate supply side resources, like battery energy storage, which can inject electricity well above normal baseline consumption.

Another option is to use aggregated control groups. In this approach, an aggregation of demand response loads is compared against a similar, statistically sampled control group. The consumption pattern of the participating demand response loads is then compared against patterns of similar customers in the region that are not enrolled in the demand response program. Comparing these two groups can quantify how demand response performs during a grid reliability event. The California Energy Commission, for example, baselines the state’s demand response against control groups and posts the aggregated data publicly to provide information on the baselining process (Glass et al., 2021). The people interviewed in this project generally considered the aggregated control group approach the best practice, appropriately balancing data needs, level of precision required, and metering burden for aggregators.

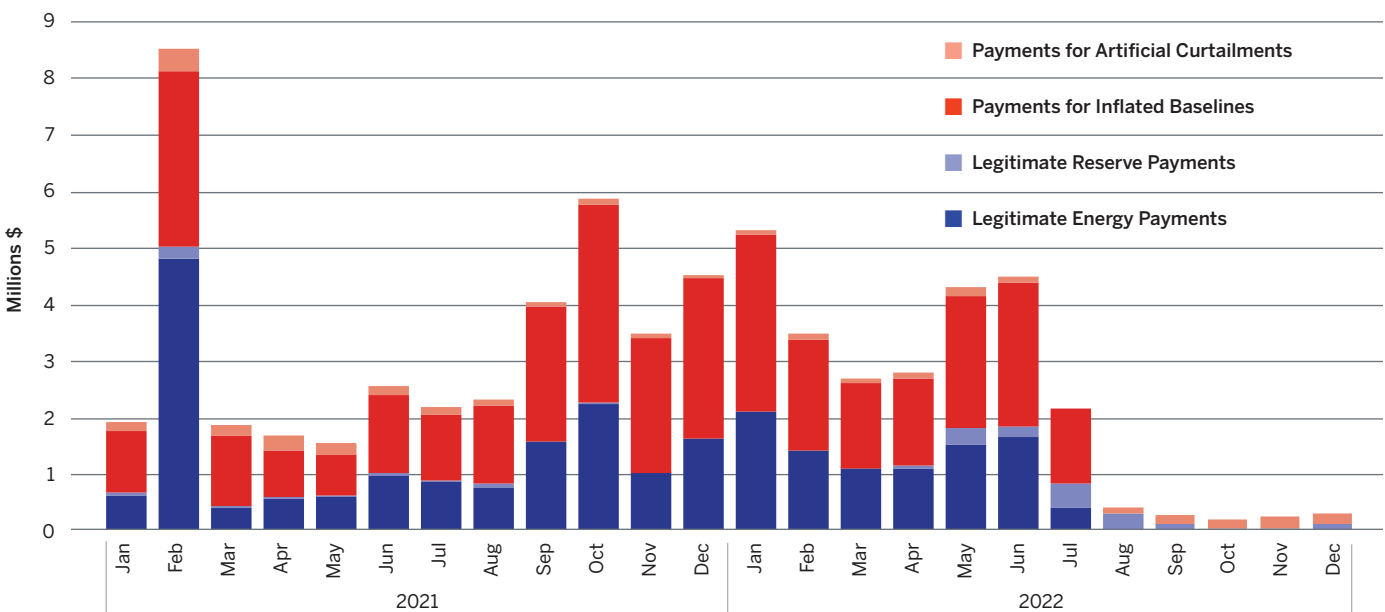
### Preventing Gaming of Market Tariffs

The implications of getting baselines right are large. In response to a \$22 million dollar increase in demand response resource (DRR) payments from 2020 to 2021, the External Market Monitor of MISO launched an investigation into how DRRs were participating in MISO’s jurisdiction. The investigation revealed two strategies employed by DRR participants to game MISO’s market tariff around settling demand response load curtailments. The gaming strategies were:

- **Artificial curtailments:** Payments for energy that the participant never intended to consume
- **Inflating the baseline:** Offering load curtailments during most hours, presumably when consumption is low, to exclude the low-consumption hours from baseline calculations

The External Market Monitor concluded that more than \$35 million of the nearly \$38 million 2021 payments to DRR Type I Resources were a result of participant gaming (Figure 10) (Potomac Economics, 2023). This

**FIGURE 10**  
Energy Market Payments to DRR Type 1 Resources in MISO, 2021–2022



The Midcontinent Independent System Operator’s External Market Monitor concluded that more than \$35 million of the nearly \$38 million 2021 payments to Type I Demand Response Resources were a result of participant gaming.

Source: Potomac Economics (2023).



investigation into MISO's DRR participation highlights some of the issues when aligning market revenue to historical load patterns.

### **Recommendations for Establishing Accurate Baselines to Build Confidence in Demand Response Resources and Provide Fair Compensation**

#### **Use Control Load Groups to Establish Baseline Load Consumption**

By leveraging industry studies, ISO market designers can explore baseline calculation methods that depend on control group baseline load rather than historical baseline load.

#### **Focus on Incremental Load Reduction**

When a demand response resource is called upon to curtail, only incremental load curtailments (through either reduced consumption or behind-the-meter injection) should be metered and relayed to system operators. If the

load is naturally low due for reasons outside of customer actions (due to mild weather, holiday or weekend load use, etc.), this should not count as a demand response curtailment.

#### **Remove Opportunities to Game Baseline Methods**

Through mechanisms such as demand response price caps, control group baseline calculations, and increased participation oversight, market designers can identify and remove gaming opportunities from their demand response participation models.

#### **Measure Both Load Reduction and Injection**

New demand response resources should include reductions in load as well as increases in generation back to the grid with behind-the-meter storage and generation resources. Many demand response markets only measure the reduction of actual consumption rather than net change in demand at the meter, leaving out opportunities for behind-the-meter resources.

## Gap 4: System operators lack detailed, publicly available information on demand response performance during emergency events, leading to inaccurate accreditation and eroding confidence in the resource.

A significant challenge for the successful integration of demand response in wholesale markets lies in the lack of detailed and transparent information on how demand response resources perform during emergency events. For example, when there is an Energy Emergency Alert event it is easy and transparent for grid operators, regulators, and stakeholders to collect hourly generation from supply-side resources and measure their availability during the event.<sup>8</sup> The data are readily available—down to an individual unit level. The same post-mortem analysis is, however, more challenging for demand response resources.

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**Without clear, reliable performance data, demand response cannot be effectively leveraged during critical periods, and its role in grid reliability remains underutilized.**

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This gap in data and performance measurement has two major consequences. First, it erodes confidence among system planners, regulators, and market participants in the reliability of demand response as a resource, which ultimately leads to onerous requirements in downstream market rules; second, it makes it difficult to accurately accredit demand response for its contributions to resource adequacy. Without clear, reliable performance data, demand response cannot be effectively leveraged during critical periods, and its role in grid reliability remains underutilized.

### The Importance of Measuring Actual Response During Emergency Events

To ensure grid reliability, demand response resources must be able to deliver on their commitments during times of system stress, particularly during Energy

Emergency Alert events. These are periods when grid operators face critical shortages of power supply and must call on demand response to help balance the system by reducing load. However, performance during these events has been difficult to measure and track, due to metering limitations, inconsistent reporting, and challenges in benchmarking performance based on ambient conditions.

The number one concern of grid operators, whether in the ISOs or at vertically integrated utilities, is the performance concern during Energy Emergency Alert events. There is a perceived risk among operators that the demand response will not be available when needed during an event, either because the load was not on the system prior to the event or because it may not respond to a deployment signal. As a result, customer response is considered an unknown, leaving operators uncertain about its efficacy.

During Winter Storm Elliott in December 2022, load curtailment estimates and measurement in PJM were misrepresented by natural demand reductions—because the winter storm happened to fall during the Christmas holiday—rather than intentional demand reductions. During that storm, demand response resources in PJM’s jurisdiction were awarded nearly \$90 million in positive compliance payments for providing an average of 120% of compliance load reduction during December 23–24, 2022 (PJM, 2023a). But despite the positive compliance findings, PJM’s Winter Storm Elliot Event Analysis report painted a much different picture on demand response activity. During the storm, PJM operators dispatched over 4,300 MW of curtailed load on December 23 and over 7,500 MW of curtailed load on December 24, but actual load reductions only reached 1,100 MW (26% of expected) on the 23rd and 2,400 MW (32% of expected) on the 24th (PJM, 2023b). The disconnect between positive compliance and negative performance can be attributed to naturally low loads without any capability of incremental reductions. When recalling the winter storm in our interviews, one aggregator operating in PJM attributed its positive demand response performance to naturally low customer loads on and

<sup>8</sup> An Energy Emergency Alert (EEA) is a NERC-defined process in which a reliability coordinator communicates potential energy deficiency events. EEA1 means all available generation is in use, EEA2 means load management procedures are in effect (including demand response), and EEA3 means involuntary load shedding is imminent or in progress. The EEA designation can be used as a useful proxy to measure demand response availability during high risk periods (NERC, 2024b).

**TABLE 3**

**Demand Response Performance During Recent Grid Emergencies**

Region	Event Date	Event Type	Committed (MW)	Delivered (MW)	Performance Ratio (%)
ISO-NE	12/24/22	Pay-For-Performance	446	203	46%
	7/5/23	Pay-For-Performance	440	138	31%
PJM	6/14/22	Emergency	94	85	90%
	6/15/22	Emergency	103	92	89%
	6/16/22	Emergency	90	69	77%
	12/23/22	Emergency	4,376	945	22%
	12/24/22	Emergency	7,323	2,158	29%
IESO	7/27/23	Emergency Hourly Demand Response (HDR) Activation	746	580	78%
	9/6/23	Emergency Hourly Demand Response (HDR) Activation	732	503	69%
	9/7/23	Emergency Hourly Demand Response (HDR) Activation	770	586	76%
NYISO	8/21/23	Targeted Demand Response Program (TDRP) Event	66	15	23%
CAISO	9/5/22	Energy Emergency Alert	160	80	50%
	9/6/22	Energy Emergency Alert	355	200	56%
	9/7/22	Energy Emergency Alert	345	170	49%
	9/8/22	Energy Emergency Alert	325	150	46%
ERCOT	8/17/23	Emergency Response Service (ERS) Event	29	35	121%
	9/6/23	Emergency Response Service (ERS) Event	995	995	100%

This table shows the percentage of demand response contribution in several recent grid emergencies relative to its contracted capacity.

Source: Energy Systems Integration Group; data sources given in the report's [online appendix](#).

before Christmas Eve, not necessarily to intentional load curtailment.

The disparity between PJM’s expected demand contributions and the actual contributions provided by demand response resources is a product of ineffective baseline methodologies. In this case, the occurrence of extreme cold weather on a holiday was not studied enough to have made a good baseline possible. So, not only does PJM’s reporting after Winter Storm Elliott lack consistency depending on the source of information (quantity of positive compliance payments vs. actual load reductions), but the actual reliability value of demand response resources presented to PJM system operators during a system event may not be consistently represented in real time.

In addition to PJM’s demand response performance during Winter Storm Elliott, Table 3 provides measured demand response contribution during select grid events across the U.S. ISO markets in recent years relative to its contracted capacity.

Data measuring demand response events are scarce and disparate for two reasons. One, the sample size is low, because Energy Emergency Alert events are, fortunately, rare. But even with the emergency events that do occur, there is no uniform collection of performance data by resource type available. Without robust data like hourly demand response deployment segmented by program, end use, or customer class, market participants and system operators cannot make informed decisions about the

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**Without robust data like hourly demand response deployment segmented by program, end use, or customer class, market participants and system operators cannot make informed decisions about the reliability and effectiveness of demand response during critical grid events.**

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reliability and effectiveness of demand response during critical grid events. This lack of confidence can lead to overly conservative market rules and requirements that may impede the participation of demand response and further discourage investment in this resource. This issue was echoed by many ISOs in our interviews, who, though often lacking substantiated data, expressed concerns about the reliability of demand response as a whole in their jurisdictions. These types of concerns erode confidence in the resource, and the best way to improve that confidence is accurate and fair accreditation of the resource for the resource adequacy contributions it provides.

### **Accurately Accrediting Demand Response for Resource Adequacy**

At its core, demand response does not have to be perfect to be valuable. All grid resources—whether demand response, wind, solar, storage, or traditional thermal capacity—are subject to variances in their actual performance during periods of system stress. The challenge lies in ensuring that demand response is properly accredited and compensated for its capacity contributions so that an ISO can properly meet its loss-of-load expectation (LOLE) and planning reserve margin (PRM) requirements. Accreditation is the process of assigning a capacity value to a resource, typically based on its effective load-carrying capability (ELCC), which measures the likelihood that the resource will perform during times of need.

For demand response, accurate accreditation is essential to building confidence in the resource and ensuring that it plays a reliable role in the overall system. It is also an important factor to provide consistency and predictability in capacity prices received by all resources and capacity

revenues for demand response specifically. This increased confidence and revenue stability will translate into further adoption.

However, there is a risk of resources' accreditation being a moving target, which introduces volatility in revenues received by demand response and the quantity offered into the market. This volatility can have significant consequences for both grid reliability and market participation. For example, in PJM, demand response resources were historically accredited at full rated capacity through the 2024/2025 auction year (PJM, 2014). Recent adjustments have reduced the ELCC for demand response to 76% in the 2025/2026 auction year, with projections that it could drop further to 50% by 2034/35 (PJM, 2024b, PJM, 2024c). The reduction to 76% was a change in the accreditation process, while the projected reduction in future years is due to saturation across all energy-limited resources. This volatility in accreditation is problematic, as it directly affects the financial viability and participation of demand response resources.

To illustrate the volatility of PJM's demand response market over time, Figure 11 (p. 34) shows offered cleared demand response in PJM, in unforced capacity, by year from the market's inception (PJM, 2024a). It shows two periods of significant decline: (1) a decline after the 2015/2016 auction when new capacity performance mechanisms and seasonal requirements were put in place, and (2) the recent reduction in the 2025/2026 auction due to new accreditation rules for demand response.

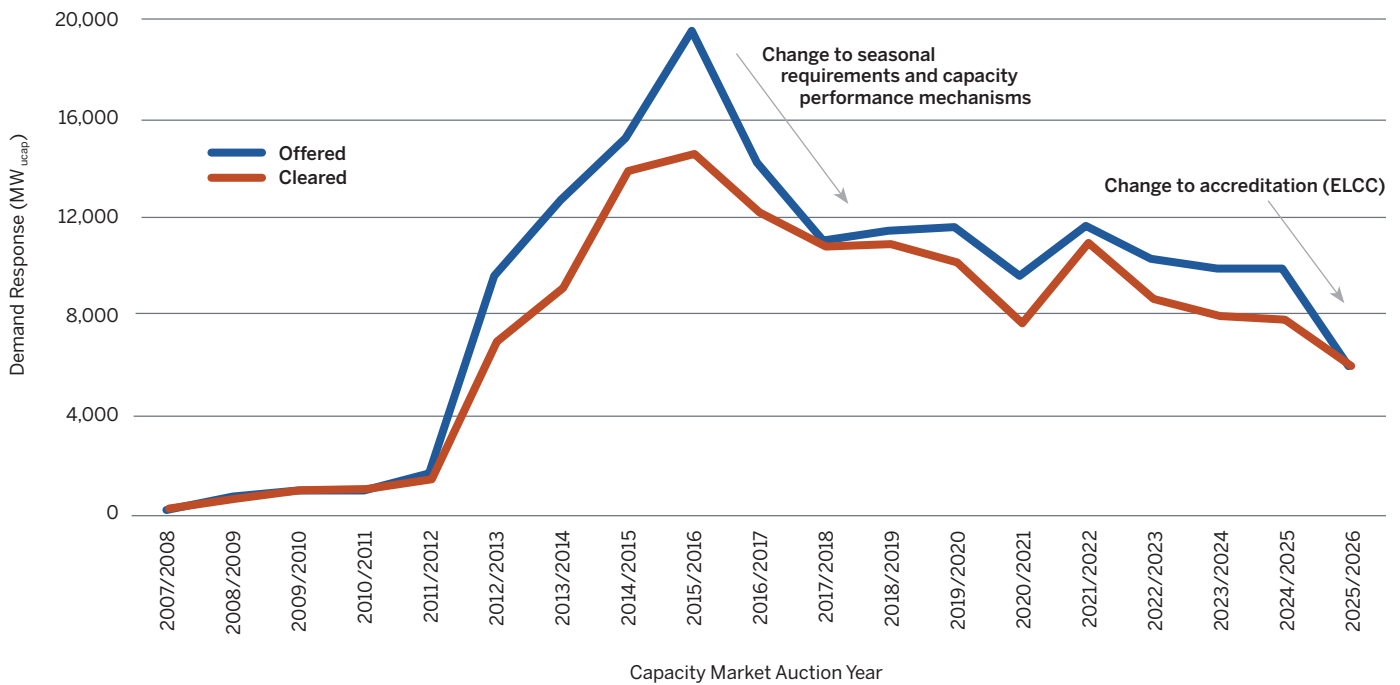
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**Accurate accreditation for demand response is essential to building confidence in the resource and ensuring that it plays a reliable role in the overall system. It also provides consistency and predictability in capacity prices received by all resources and capacity revenues for demand response specifically. This increased confidence and revenue stability will translate into further adoption.**

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**FIGURE 11**

**Offered and Cleared Demand Response Capacity in the PJM Capacity Market, 2007–2026**



This chart shows offered cleared demand response in PJM, in unforced capacity, by year from 2007. There are two periods of significant decline: after the 2015/2016 auction when new capacity performance mechanisms and seasonal requirements were put in place, and in the 2025/2026 auction due to new accreditation rules for demand response.

Source: Energy Systems Integration Group; data from PJM (2024).

### Addressing Seasonal and Frequency/Duration Availability of Demand Response Technologies

Seasonal capacity markets and accreditation can also help. Some demand response programs, particularly thermostat control, can be available during some seasons but not others. For example, a summer air conditioning control can have significant capacity benefits for summer afternoons and evenings but provides no value in the winter. An annual capacity market would significantly discount this resource, while a seasonal construct would allow high accreditation in the summer season and not require bundling of other demand response resource types in other seasons.

In addition to seasonal limitations, demand response technologies can vary significantly in frequency, duration, and hourly availability of service. For example, an electric vehicle charging program may be available predominantly at night and can be deployed for an extended time frame, while a smart thermostat program would be available

When demand response aggregators and wholesale regulators take technical limitations into account when matching accreditation to system needs, the contributions of certain demand response technologies can be more fully captured.

only for a few hours during evening peak. When demand response aggregators and wholesale regulators take technical limitations into account when matching accreditation to system needs, the contributions of certain demand response technologies can be more fully captured.

### Reducing Volatility Through Accreditation That Is Fair, Stable, and Based on Accurate Data

Accreditation needs to be fair, stable, and based on accurate data. Volatility in capacity accreditation will lead to uncertainty in participation, which undermines

confidence in the resource and creates unnecessary risks for grid operators. All resources, including demand response, must be accredited in a consistent way that reflects their actual capabilities. While technologies like wind, solar, and storage have seen significant attention to their accreditation in recent years, ISOs are only now starting to consider changes to demand response accounting processes.

To overcome this accreditation challenge, forensic reports on demand response performance need to be conducted after every Energy Emergency Alert event, providing a detailed analysis of how demand response resources performed relative to their obligations. This kind of post-event analysis would provide invaluable data for refining accreditation methodologies and ensuring that demand response resources are fairly credited for their contributions.

## Recommendations for Improving Data and Accreditation

To close the gap in demand response performance data and accreditation, the following steps can be taken.

### Conduct Forensic Reporting for Energy Emergency Alert Events

Every time an Energy Emergency Alert event occurs, a detailed report can be generated to analyze how all resources—including demand response—performed relative to their accredited capacity. This report would be made publicly available to enhance transparency and build confidence in demand response as a reliable resource.

### Ensure Stable and Fair Accreditation

Accreditation methodologies, including ELCC, need to be stable and predictable. Sudden changes in accreditation can lead to significant volatility in demand response participation. ISOs can work to ensure that all resources—including demand response—are accredited in a consistent manner, based on their demonstrated performance and value to the grid. By setting clear guidelines for how demand response will be accredited and ensuring that these rules remain stable over several years, ISOs can

provide demand response providers with the confidence they need to invest in these resources.

### Perform Standardized Data Collection and Verification

A consistent approach to data collection and verification needs to be adopted across all ISOs. This would involve creating uniform baselining methodologies, clear performance reporting requirements, and standardized metrics for measuring the contribution of demand response during emergency events.

### Improve Baselining Techniques

ISOs, LSEs, and third-party aggregators need to explore new baselining techniques, such as anonymized customer data comparisons and aggregated control groups, to ensure that demand response resources are not miscredited for their contributions. This would also allow for a more accurate assessment of performance during both test and real-world events.

By addressing these key issues, demand response can be fully integrated into the resource adequacy planning of ISOs, ensuring that it is fairly compensated for its contributions while maintaining reliability in the grid. Improved data collection and accreditation are essential steps toward making demand response a core component of the energy system's reliability and flexibility toolkit.

**Gap 5: There are weak financial incentives, and even disincentives, for demand response at the wholesale market, load-serving entity, and customer levels.**

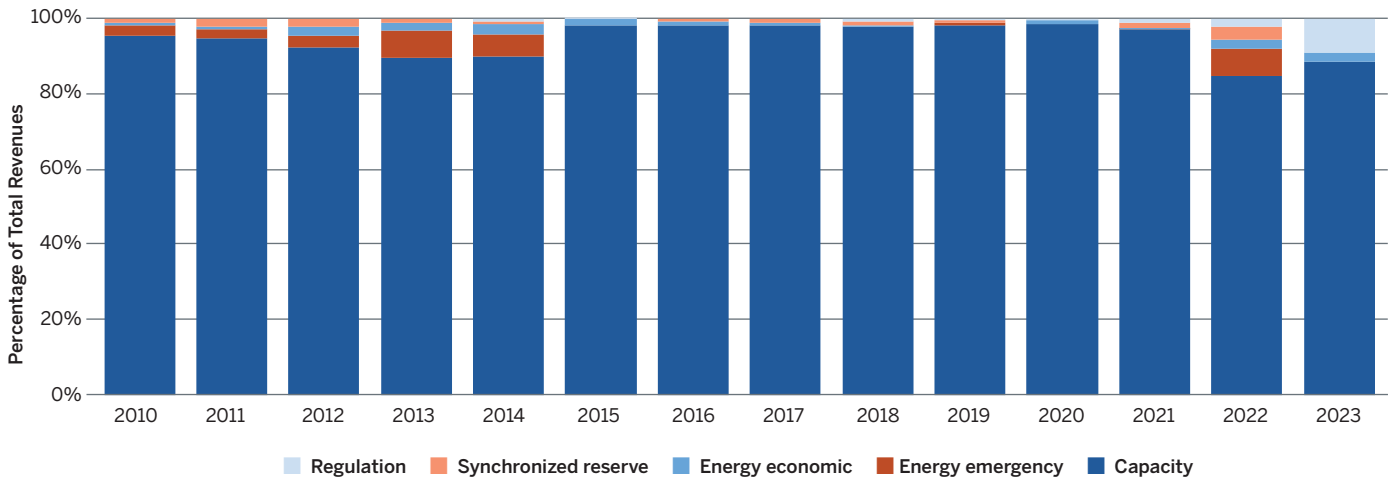
## Volatile Wholesale Capacity Markets

One of the most significant barriers to demand response participation is the volatility of capacity markets, which do not provide a stable financial signal for long-term investment. Much of the demand response participation in ISO markets today is centered around capacity markets (Monitoring Analytics, 2024) (Figure 12, p. 36),<sup>9</sup> where payments are tied to the ability of demand response resources to defer generation capacity. However, capacity markets are notoriously volatile, with clearing prices

<sup>9</sup> This is most applicable to ISOs with mandatory capacity markets (PJM, NYISO, and ISO-NE), but is also true in other markets that have a capacity obligation for LSEs (MISO, SPP, IESO, CAISO) and a residual capacity market to fill in any deficiencies.

FIGURE 12

Demand Response Revenue by Source in PJM, 2008–2023



This figure shows a breakdown of demand response revenues in PJM, by revenue source, from 2010 to 2023, illustrating how capacity revenues make up more than 90% of all demand response revenues.

Source: Monitoring Analytics (2024).

fluctuating year to year based on supply and demand dynamics. This volatility creates an unstable environment for demand response providers, who rely heavily on capacity payments as a key revenue stream.

While more flexible load resources such as behind-the-meter battery storage, electric vehicles, and more advanced virtual power plants are starting to deploy for energy and ancillary market services, the capacity market is still the largest source of revenues for demand-side resources, and most interviewees believe it will continue to be for the foreseeable future.

**Volatile Capacity Prices' Ability to Erode Investment Confidence**

Capacity markets are designed to procure enough resources available in the future to meet peak load (either one or three years ahead), but the prices in these markets fluctuate significantly. For demand response providers, this volatility presents a major challenge because the financial incentives tied to capacity prices vary from year to year. For instance, when capacity prices rise, demand response providers may find it lucrative to participate, but when prices fall, participation declines, making it difficult to plan and maintain a stable demand response portfolio over time.

Theoretically, this volatility is a primary reason demand response could be preferred as a capacity resource over other options. Unlike traditional forms of generating capacity—i.e., a combustion turbine—demand response requires much less infrastructure to deploy. Flexibility in deployment allows demand response to enter or exit the market as the marginal resource, providing a buffer for this volatility. In the Independent Electricity System Operator in Ontario (IESO), for example, the capacity market actually started in 2015 as a demand response-only auction, providing a residual market to meet capacity needs from year to year; it was only later that other resources were able to participate (IESO, 2015). But despite this advantage of less capital deployment, price and revenue certainty are still a critical part of an aggregator's business model and ability to attract new customers.

**The Disruptive Impact of Accreditation Changes**

The financial uncertainty in demand response markets is further compounded by the volatility in resource accreditation, which leads to variation in the supply that load resources can provide. In other words, demand response sees volatility with regard to both the market clearing price and the quantity they are remunerated for. ISOs have recently been adjusting their accreditation methodologies frequently, a reaction to variable renewable and

energy-limited resources becoming a large part of the resource mix and the resulting shifting size, frequency, duration, and timing of resource adequacy risk. These shifts required a change to accreditation in many markets, but implementation was often piecemeal—first being applied to wind and solar resources, then applied to battery storage, and not being considered for thermal resources and demand response.

A small change in how a demand response resource's capacity is accredited can have profound impacts on its revenues. For example, in PJM's recent capacity auction, the market clearing price increased by over 800%, but demand response participation dropped due to changes in accreditation rules rather than market signals. This shift is a major deterrent for investment because demand response providers have little control over how their capacity is evaluated and accredited. If ISOs reduce the accredited capacity of demand response even though the resource might still be capable of providing the same level of service, revenues will drop, further eroding financial viability.

### **The Disproportionate Effect of Capacity Market Changes on Demand Response Resources**

Energy resources other than demand response benefit from a range of financial incentives that shield them from the volatility of capacity markets. Wind and solar projects often benefit from federal tax incentives, such as the investment tax credit and production tax credit, which provide significant financial support for their development. Additionally, many renewable energy projects receive revenues through state renewable portfolio standards and long-term contracts with corporate buyers. These incentives provide a stable, predictable revenue stream for renewable energy developers, typically locked in for 10 to 20 years. Transmission infrastructure similarly benefits from long-term recovery mechanisms that ensure stable returns on investment over time.

In contrast, demand response is much more exposed to the whims of short-term market conditions. The lack of long-term financial certainty in demand response markets makes it difficult for providers to secure the capital needed to scale their operations or invest in new technologies.



### **Recommendations to Provide Price Stability**

To overcome the challenge of volatile capacity revenues for demand response resources, several approaches can be considered.

#### **Create Incentives for Long-term Contracts for Demand Response Resources**

Regulators can create incentives for LSEs to enter into long-term contracts for demand response, similar to how power purchase agreements are structured for renewable energy. A “contracts for differences” approach could be employed, where demand response providers are paid a fixed price, minus the revenues they receive from the wholesale market. This approach would provide a stable revenue stream over a longer time horizon, reducing the risk of market volatility.

#### **Allow Self-accreditation**

Market designers can consider allowing demand response, and other resources, to self-accredit in offering their firm capacity into the capacity market. This would allow aggregators to lock in the capacity contribution their resource can provide while taking on the risks of non-performance and potential penalties. Aggregators could then hedge this risk accordingly, but ultimately the change would allow for more stable financing.

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**Allowing demand response to participate as transmission and distribution assets, it could benefit from long-term rate recovery mechanisms similar to transmission infrastructure and be embedded in an ISO transmission planning process rather than (or in addition to) the market.**

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#### **Allow Demand Response to Participate as Transmission and Distribution Resources**

Another option is to allow demand response to participate as transmission and distribution assets. By treating demand response as a non-wires alternative, it could benefit from long-term rate recovery mechanisms similar to transmission infrastructure and be embedded in an ISO transmission planning process rather than (or in addition to) the market. This would provide a more stable financial environment for demand response, encouraging investment in resources that can provide both capacity and grid reliability services. Similar suggestions are being made to treat storage as a transmission asset for these reasons. This would require a significant change to transmission planning and cost allocation methods to allow demand response to be considered in regional transmission plans and for transmission reliability.

#### **Load-Serving Entities' Financial Incentive to Discourage Demand Response**

One of the more complex challenges to demand response participation is the inherent financial disincentives for LSEs to encourage demand response. This issue is most applicable when LSEs retain the right to own and self-build new generation resources. While LSEs have a responsibility to ensure reliable service to their customers, the financial mechanisms governing LSE operations can create conflicting priorities. Specifically, the structure of LSE finances and the way capital investments are treated can lead to situations in which LSEs are financially motivated to avoid demand response programs even though these programs could reduce costs for customers.

#### **An Incentive to Focus on Capital Expenditures**

LSEs typically have the opportunity to earn a regulated rate of return on capital expenditures, such as building

new generation capacity or upgrading transmission and distribution infrastructure. This rate of return is a fundamental part of the traditional utility business model, as it provides a stable income stream for LSEs while they make large capital investments. In contrast, demand response programs are often treated as operating and maintenance (O&M) expenses, which do not qualify for the same returns. Simply put, when LSEs reduce capacity needs or defer transmission and distribution upgrades through demand response programs, they also reduce their opportunity to make capital investments. This dynamic creates a perverse incentive where it may be more financially attractive for LSEs to avoid demand response, even though it could lower overall costs for customers by reducing peak demand and deferring costly upgrades.

This perverse incentive is most pronounced in ISO markets where LSEs are permitted to self-build capacity (i.e., SPP and MISO) and in vertically integrated utilities. Even in ISOs that decoupled generation investment (ISO-NE, NYISO, PJM, and CAISO) and do not allow LSEs to self-build capacity, LSEs can simply pass capacity costs on to their customers, recovering the expenses through higher rates. In this scenario, there is no significant financial advantage for an LSE to promote demand response because the capacity procurement costs can be recouped without reducing the utility's rate of return.

However, while this financial disincentive exists, LSEs are also obligated by their regulators to keep customer rates as low as possible. Some stakeholders argue that this responsibility should outweigh any financial preferences for capital investments over demand response programs. Indeed, many LSEs continue to emphasize their commitment to serving customer needs by providing cost-effective solutions, even if those solutions do not maximize the utility's rate of return. However, retail demand response programs still have yet to see significant investment despite advancements in demand response technology.

A similar challenge exists for energy efficiency and rooftop solar deployment. They reduce both the revenues an LSE receives by selling electricity to customers and the cost recovery it would receive for the capacity resources it would build to serve that load.

### The Potential for Shifting Priorities

Despite these financial disincentives, there is a growing shift in how LSEs view demand response, particularly in light of new load growth driven by factors such as electrification and data center expansion. As large loads come online, LSEs are increasingly looking for ways to free up capacity on their systems—including generation, transmission, and distribution needs—to accommodate new customers and growing demand. In this context, demand response could become a valuable tool for managing new load interconnection and creating the necessary headroom to bring on additional capacity without immediately investing in new infrastructure.

In these cases, demand response can serve as a bridge, allowing LSEs to develop major capital investments that have long deployment times while growing total customer demand and interconnecting new large-paying customers. As demand for electrification continues to rise, particularly with the increased adoption of electric vehicles and other high-demand technologies, LSEs may find that demand response helps them manage the grid more flexibly and efficiently, reducing the conflict between their financial goals and the operational benefits of demand response.

### Recommendations to Increase LSEs' Financial Incentives to Build Out Demand Response

To overcome the disincentive for demand response programs at LSEs, various regulatory changes can be implemented, including the following.

#### Allow the Capitalization of Demand Response–Related Costs

LSEs can be allowed to capitalize expenses associated with demand response, including contract costs and customer incentives, enabling these costs to be treated as investments with a return, similar to physical infrastructure.

#### Implement Shared Savings Mechanisms

Shared savings programs can be implemented in which LSEs share in the cost savings generated by demand response programs. This approach provides a financial reward to LSEs for reducing overall system costs through demand response.

### Use Performance-Based Rates

Performance-based rate structures can be developed that reward LSEs for meeting specific demand response goals, such as peak-load reduction or improved reliability metrics. This encourages LSEs to prioritize demand response in their resource planning. Multi-year rate plans can set clear benchmarks for demand response growth and associated revenues.

### Introduce Demand Response Investment Adders

Rate adders can be introduced that increase the allowable return on investments in demand response programs, providing a similar financial incentive as infrastructure projects and encouraging LSEs to allocate more resources toward these programs.

Ultimately it is up to the regulators to determine the appropriate rate recovery mechanisms to ensure that demand response options are fairly considered by the LSEs.

### The Inability of Rate Design to Incent Demand Response Participation

Another barrier to demand response participation lies in the design of electricity rates. In many regions, including those in wholesale markets, rate structures fail to incent customers—residential, commercial, or industrial—to participate in demand response programs. Specifically, flat volumetric rates commonly used for electricity billing do not reflect the dynamic nature of electricity costs, which vary significantly based on when and where electricity is consumed. Even in wholesale ISO markets with transparent location-based marginal pricing, the end-use customer rarely pays a rate reflective of the time- and location-varying wholesale costs. This misalignment

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**Shared savings programs can be implemented in which LSEs share in the cost savings generated by demand response programs. This approach provides a financial reward to LSEs for reducing overall system costs through demand response.**

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disconnects wholesale market signals from the financial incentives customers receive for adjusting their energy use.

Time-varying rates are the enabler to get customers engaged in energy management. They serve as a motivator to manage loads and reduce costs. Once this happens, customers have the knowledge and enabling technologies to then offer into demand response programs, which rewards providers with additional revenues.

### The Problem with Flat Volumetric Rates

Flat volumetric rates, where customers pay a fixed price per kilowatt-hour regardless of the time of day or system conditions, are widespread. While these rates simplify billing for both LSEs and customers, they fail to provide the necessary price signals to encourage load management. In wholesale electricity markets, prices fluctuate throughout the day and year, reflecting grid conditions such as high demand or low supply. However, customers who pay flat rates are not exposed to these real-time price signals and therefore have little incentive to shift their consumption patterns in response to grid needs (Olson et al., 2023).



Flat volumetric rates are most common for residential, commercial, and small industrial customers, which rarely participate in demand response unless they are on specialized time-of-use or peak-demand retail pricing programs. Even when such programs are available, they are often voluntary and hence underutilized. As a result, the vast majority of customers are unaware of the potential value of managing their electricity use to align with wholesale market conditions. Moreover, our interviews for this project showed that both aggregators and utility demand response program managers also see a lack of incentive for larger industrial customers. In this case, demand response revenues are often viewed as too small to justify significant changes in their operations. For these customers, the complexity and risks involved in adjusting production schedules can outweigh the financial benefits of participating in demand response programs.

Figure 13 (p. 41) shows the percentage of total utility customers enrolled in dynamic retail rates at the end of 2022. Dynamic rates tracked in the EIA database include time-of-use pricing, real-time pricing, variable peak pricing, critical peak pricing, and critical peak rebates (U.S. EIA, 2024). Across the U.S. only 10% of customers are enrolled in some form of dynamic pricing. This is highest among commercial and industrial customers (12%) and lower among residential customers (9%). States like Arizona, Maryland, and Delaware, which have high enrollment in dynamic pricing programs (34%, 37%, and 68%, respectively) also have the highest enrollment in demand response programs (25%, 42%, and 48%).<sup>10</sup> Even within a state there can be considerable differences. For example, Arizona Public Service has 55% enrollment in dynamic rates and 60% enrollment in demand response, much higher than the state average.

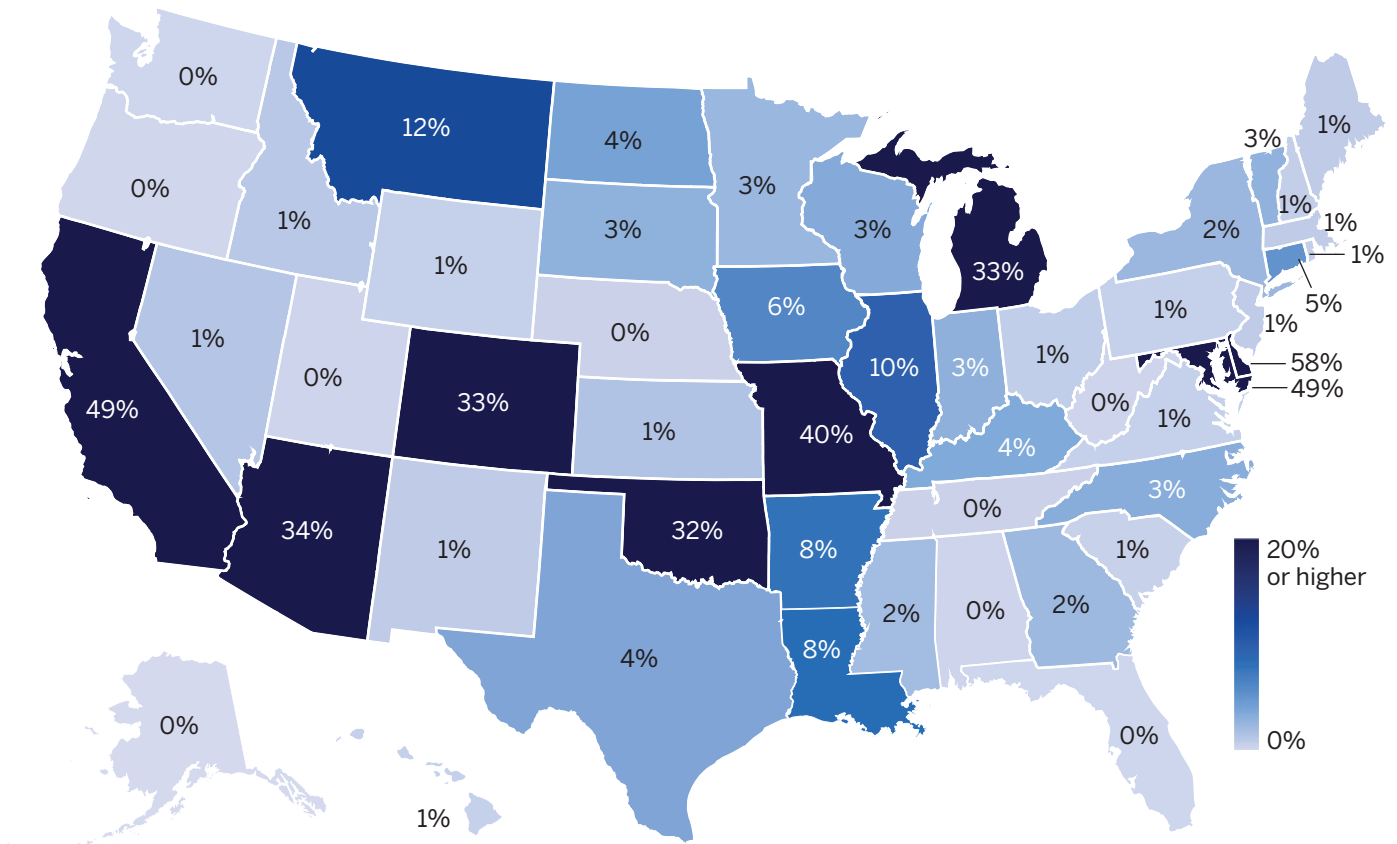
### The Role of Retail Rate Design in Demand Response Participation and Ability to Respond to Wholesale Market Needs

Properly structured rate design has the potential to align retail price signals with wholesale market needs and significantly increase demand response participation. Time-of-use pricing, critical peak pricing, and demand

<sup>10</sup> The notable exceptions to this relationship are California, which has high participation in time-of-use rates (50%) but low participation in demand response (4%), and Minnesota, which has low participation in dynamic pricing (2%) but relatively high participation in demand response programs (28%).

FIGURE 13

Percentage of Total Utility Customers Enrolled in Dynamic Pricing, 2023



This map shows the percentage of total utility customers (residential, commercial, and industrial) enrolled in dynamic retail rates at the end of 2023. Dynamic rates tracked in the EIA database include time-of-use pricing, real-time pricing, variable peak pricing, critical peak pricing, and critical peak rebates.

Source: Energy Systems Integration Group; data from U.S. Energy Information Administration Form 861.

charges are all mechanisms that can help achieve this alignment. For example, in the IESO market in Ontario, the wholesale demand response participation is robust, but much of this participation is driven by large customers that seek to manage their loads to avoid critical peak demand charges in their retail rates rather than to capture capacity market revenues (IESO, 2024). By engaging with service providers and aggregators to reduce their load during peak demand events, these customers meet their needs to reduce their electricity costs, but also have all of the technology and relationships set up with aggregators which can then offer that capacity into the market. Without the dynamic rate design, the end-use customers would have been much less likely to engage with technology providers managing their load.

In this way, retail rate design can work in tandem with demand response participation. On one hand, demand charges serve as a “stick” by penalizing customers for consuming electricity during high-cost periods, while on the other hand, demand response revenues serve as a “carrot” by rewarding customers who successfully reduce their load during times of grid stress. By coordinating retail rate design with demand response programs, LSEs

**By coordinating retail rate design with demand response programs, LSEs can provide customers with both the motivation and the financial means to participate in load management.**

**TABLE 4**

**Customers Enrolled in Dynamic Pricing and Demand Response by ISO, 2023**

ISO	Customers Enrolled in Dynamic Pricing	Customers Enrolled in Demand Response Programs	Total Customers	Participation in Dynamic Pricing (%)	Participation in Demand Response (%)
CAISO	7,072,000	489,000	13,087,000	54%	4%
ERCOT	339,000	725,000	12,346,000	3%	6%
SPP	1,878,000	374,000	7,949,000	24%	5%
MISO	2,889,000	2,041,000	23,991,000	12%	9%
PJM	2,316,000	2,655,000	31,140,000	7%	9%
NYISO	204,000	158,000	8,572,000	2%	2%
ISO-NE	144,000	101,000	7,488,000	2%	1%
<b>TOTAL</b>	<b>14,842,000</b>	<b>6,542,000</b>	<b>104,574,000</b>	<b>14%</b>	<b>6%</b>

This table shows customer enrollment in retail dynamic pricing and demand response programs in 2023, as reported by the load-serving entities in EIA Form 861 along with the percentage of total customers.

Source: Energy Systems Integration Group; data from U.S. Energy Information Administration Form 861 (U.S. EIA, 2024).

can provide customers with both the motivation and the financial means to participate in load management. Table 4 provides an overview of customer enrollment in retail dynamic pricing and demand response programs, as submitted by LSEs in the ISO balancing authorities, but does not include all demand response resources participating directly in the wholesale market.

It should be noted that while time-varying rates can be an incentive for load flexibility, they are by themselves not the same as controllable demand response programs that respond to day-ahead or real-time grid conditions. Instead, they can be an enabler of this type of response by getting the requisite interest, controls, and enabling technologies in place.

Although retail rates are beyond the direct control of wholesale market designers at ISOs, there are opportunities for ISOs to incent load management through wholesale market structures. For instance, demand charges or transmission access charges incurred by the LSE based on its total peak consumption could be used to encourage LSEs to manage their overall system load during peak demand periods. An example of this is ERCOT’s Four Coincident Peak Calculations (4CP) used to allocate transmission costs to LSEs.

**Recommendations for Overcoming Rate Design Challenges**

To address the shortcomings of current rate designs and encourage broader demand response participation, several steps can be taken.

**Coordinate Retail Rate Design and Demand Response Programs**

Retail rate design and demand response initiatives need to be closely aligned to maximize the financial benefits for both customers and utilities. A combination of demand charges and demand response incentives can create a balanced approach that rewards load management while penalizing consumption during periods of grid stress. But to do this effectively, it is important for the time-varying structure of rates to align with the grid needs when demand response is most required.

**Transition away from Flat Volumetric Rates**

At both the retail and wholesale levels, rates can incorporate demand charges for transmission and generation capacity. This would provide a clear incentive for LSEs to manage their load during peak periods and create opportunities for demand response and efficiency programs that align with customer interests. Regulators and LSEs



may consider accelerating the adoption of time-varying rates to at least partially expose customers to the true costs of electricity during periods of high demand. These pricing structures can be integrated with demand response programs to encourage participation.

### **Enable Value Stacking**

Rate structures should allow demand response to provide multiple services across the grid, from providing generation capacity to allowing the deferral of transmission and distribution system upgrades. Allowing demand response to offer into both retail programs administered by LSEs and wholesale market programs can amplify *both* the benefits of demand response and the financial incentives they receive. This value stacking would maximize the financial incentives for LSEs and customers to participate

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**Allowing demand response to offer into both retail programs administered by utilities/LSEs and wholesale market programs can amplify both the benefits of demand response and the financial incentives they receive.**

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in demand response programs, while enhancing grid reliability.

By improving rate design and aligning it with demand response programs, LSEs can create stronger financial incentives for customers to manage their energy use, leading to greater participation in demand response and improved grid reliability.

# Potential Solutions and a Path Forward

This report has highlighted five critical gaps in the integration of demand response into wholesale markets. Each gap presents unique challenges that can be addressed to unlock the full potential of demand response. This is especially true as capacity needs across the United States increase due to coal, gas, and nuclear retirements and as new forms of load flexibility like electric vehicles and behind-the-meter storage see increased adoption. This section provides targeted recommendations for each gap (Figure 14), drawn from interviews with key subject-matter experts.

## Solution 1: Strengthen experience and knowledge in demand response technology and programs among system operators, state regulators, and consumers.

Without a clear understanding of how demand response technologies can contribute to grid reliability and resilience,

participation and investment will remain limited. This can be improved with the actions given in Table 5 (p. 45).

## Solution 2: Clarify demand response program boundaries across retail and wholesale programs and harmonize market rules across ISOs and LSEs.

The dual participation options in retail and wholesale demand response markets create confusion and inefficiencies. There is also a lack of uniformity in program design, rules, and incentives across ISOs and LSEs, which hinders the scalability of demand response programs. While it might be tempting to focus on achieving “perfection” in individual demand response program rules—for example, by adjusting a specific metering or telemetry rule—it is more productive to seek consistency in market rules across jurisdictions. Solutions include those listed in Table 6 (p. 45).

**FIGURE 14**  
Five Potential Solutions and a Path Forward in Demand Response Participation

Experience and Knowledge	Program Boundaries and Rules	Communication and Metering	Performance and Accreditation	Financial Incentives and Retail Rates
Strengthen experience and knowledge in demand response technology and programs among system operators, state regulators, and consumers	Clarify demand response program boundaries across retail and wholesale programs and harmonize market rules across independent system operators	Refine communication and metering requirements to facilitate the integration of demand response into wholesale markets	Use detailed information on demand response performance during emergency events to improve accreditation and ensure reliability, while building confidence across stakeholders	Align financial incentives to stabilize revenues from long-term demand response contracts, incent load-serving entities to defer new capacity, and align customer rates

Source: Energy Systems Integration Group.

TABLE 5

Ways to Increase Understanding of How Demand Response Technologies Can Contribute to Grid Reliability and Resilience

Attributes	Actions
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Identify program administrators at ISOs.</b> Each ISO can have a dedicated subject-matter expert responsible for managing the market design and wholesale demand response programs. While this does not have to be the expert’s sole responsibility, it is important to have someone responsible and who identifies as the lead on demand response topics.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Develop educational programs for power industry stakeholders.</b> Demand response capacity-building and education programs can be established to share best practices across wholesale markets.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Collect more data.</b> The U.S. Energy Information Administration, Federal Energy Regulatory Commission, and North American Electric Reliability Corporation need to continue and expand data collection for current demand response, dynamic rate, and load flexibility program participation, to be updated regularly in order to incrementally track progress.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Empower customers.</b> Load-serving entities can invest in simplified enrollment processes and easy-to-use platforms and monitoring tools to provide customers with information about their hourly energy use and how their load curtailment or grid injections can improve reliability.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Automate enrollment.</b> Load-serving entities can consider opt-out provisions rather than elective, opt-in participation in future customer demand response and dynamic pricing programs. Program participation will improve if all customers are automatically enrolled in load-serving entities’ dynamic pricing or demand response programs, while retaining their ability to opt out of the program entirely or for individual events.</p>

■ High ease, high impact, or good progress is being made    ■ Medium ease, medium impact, or some progress is being made  
 ■ Little ease, little impact, or no progress is being made

Source: Energy Systems Integration Group.

TABLE 6

Solutions to Confusion Around Dual Participation Options and the Lack of Uniformity in Program Design, Rules, and Incentives Across ISOs and Load-Serving Entities

Attributes	Actions
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Clarify, then integrate wholesale and retail programs.</b> Market designers can work closely with load-serving entities to clearly and transparently distinguish between and count wholesale and retail demand response programs, and identify where value stacking across programs is present. This reporting consistency should also be reflected by the U.S. Energy Information Administration Form 861 and in the Federal Energy Regulatory Commission’s yearly <i>Assessment of Demand Response and Advanced Metering</i> reports.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Focus on cooperative rulemaking.</b> Often, wholesale market designers create negative incentive structures that favor traditional generation resources. Market designers need to continue working closely with their demand response providers to develop a fair, stable, and competitive market structure for demand response that operates in tandem with the rest of the wholesale energy market.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Strive for consistency, not for perfection.</b> Based on our interviews with aggregators, one of the most important enablers for increased demand response participation in wholesale markets is consistent and stable market rules, metering, and communication standards across wide areas. ISOs should strive to make participation rules consistent and only develop unique requirements if there is a clear rationale to do so. This would allow technology providers and aggregators to develop common products and business models across markets.</p>

Source: Energy Systems Integration Group.

**Solution 3: Refine communication and metering requirements to facilitate the integration of demand response into wholesale markets.**

Stringent communication and metering requirements often make it difficult for smaller or distributed demand response resources to participate in the wholesale markets, even if an aggregator takes on this responsibility. These operational barriers disproportionately affect residential and small commercial customers, where much of the

untapped potential for demand response lies. Solutions to this barrier are given in Table 7.

**Solution 4: Use detailed information on demand response performance during emergency events to improve accreditation and ensure reliability, while building confidence across stakeholders.**

The absence of transparent, reliable data on wholesale market demand response performance during emergency

**TABLE 7**  
**Solutions to Communication and Metering Requirements That Often Make It Difficult for Smaller or Distributed Demand Response Resources to Participate in Wholesale Markets**

Attributes	Actions
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Use control load groups to establish baseline load consumption.</b>                      By leveraging industry studies, ISOs can explore baseline calculation methods that depend on control group baseline load rather than historical baseline load.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Measure both load reduction and injection.</b>                      Although new demand response resources can include reductions in load as well as increases in generation back to the grid with behind-the-meter storage and generation resources, many demand response markets measure only the reduction in consumption rather than net change, creating missed opportunities for behind-the-meter resources.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Consider aggregations of non-revenue-grade meters.</b>                      Market operators should evaluate aggregations of less-accurate metering technologies to measure demand curtailment and/or grid injections. Large groups of energy metering devices such as inverters may be able to provide accurate enough revenue-grade measurements.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Modify the minimum size of aggregations.</b>                      While size requirements need to exist to limit the administrative burden of running a wholesale market, ISO market designers should not significantly limit residential demand response due to an administratively set value, especially at the individual resource level. Regulators and aggregators can explore different sizing options that encourage all levels of demand response participation at the wholesale level.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Integrate nodal congestion pricing into demand response settlements.</b>                      By leveraging location-based pricing methods, ISOs can allow demand response aggregations to be settled across multiple locations in order to meet administrative sizing requirements. By doing so, aggregators and load-serving entities would be able to package bulk demand-response aggregations without the hassle and administrative burden of splitting by locations.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Standardize metering requirements.</b>                      ISOs, the Federal Energy Regulatory Commission, and the North American Electric Reliability Corporation can coordinate with regional entities on a consistent metering method that can apply across all demand response technology types in all regions. Ensuring consistency across regions could encourage widespread investment into appropriate metering technologies at the wholesale level.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Strive for interoperability between platforms.</b>                      Load-serving entities and aggregators can strive to build platforms to manage all end uses under a single platform or via robust interoperability between platforms—as opposed to disparate platforms for thermostat, electric vehicles, and building management systems.</p>

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Source: Energy Systems Integration Group.

**TABLE 8**

**Improvements Needed to Data Collection and Resource Accreditation for Demand Response Performance**

Attributes	Actions
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Do forensic reporting for Energy Emergency Alert events.</b> Every time an Energy Emergency Alert event occurs, a detailed report can be generated to analyze how demand response resources performed relative to their accredited capacity. Making these reports publicly available will enhance transparency and build confidence in demand response as a reliable resource.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Standardize data collection and verification.</b> A consistent approach to data collection and verification adopted across all ISOs would better inform new and existing demand response participants on opportunities and shortfalls in the space. This would involve creating uniform baselining methodologies, clear performance reporting requirements, and standardized metrics for measuring the contribution of demand response during emergency events.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Allow for seasonal accreditation.</b> Some demand response programs, particularly thermostat control, can be available during some seasons but not others. For example, a summer air conditioning control can have significant capacity benefits for summer afternoons and evenings but provides no value in the winter. An annual capacity market would significantly discount this resource, while a seasonal construct would allow high accreditation in the summer season and not require bundling of other demand response resource types in other seasons.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Undertake stable and fair accreditation.</b> Accreditation methodologies, including effective load-carrying capability (ELCC), must be stable and predictable. Sudden changes in accreditation can lead to significant volatility in demand response participation. ISOs need to work to ensure that demand response is accredited based on its demonstrated performance and value to the grid. By setting clear guidelines for how demand response will be accredited and ensuring that these rules remain stable over several years, ISOs can provide demand response providers with the confidence they need to invest in these resources.</p>

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Source: Energy Systems Integration Group.

events erodes confidence in the resource and complicates the process of accrediting demand response for its contributions to resource adequacy. To bridge this gap, wholesale markets can make the improvements to data collection and accreditation described in Table 8.

**Solution 5: Align financial incentives to stabilize revenues from long-term demand response contracts, incent LSEs to defer new capacity, and align customer rates.**

Demand response participation is hindered by weak financial incentives, particularly in volatile capacity

markets. Moreover, LSEs often have financial disincentives to encourage demand response, as it reduces their ability to invest in new infrastructure and generate returns on those investments. In order to align incentives, the recommendations in Table 9 (p. 48) can be employed.

By implementing these actions, the integration of demand response into wholesale markets can overcome the key barriers we outlined in this report, driven by our interviews with third-party aggregators, ISOs, non-governmental organizations, and market researchers. Taking these steps will help unlock the full potential of demand response as a flexible, scalable, reliable resource in wholesale electricity markets.

TABLE 9

Ways to Align Financial Incentives Both for Demand Response Resources and for Load-Serving Entities

Attributes	Actions
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Create incentives for long-term contracts for demand response resources.</b></p> <p>Regulators can create incentives for load-serving entities to enter into long-term contracts for demand response, similar to how power purchase agreements are structured for renewable energy. A “contracts for differences” approach could be employed, where demand response providers are paid a fixed price, minus the revenues they receive from the wholesale market. This approach would provide a stable revenue stream over a longer time horizon, reducing the risk of market volatility.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Enable value stacking.</b></p> <p>To more fully capture the contribution of demand response to grid reliability, retail rate structures should allow load-serving entities’ demand response programs to provide multiple services across the grid, from generation capacity to transmission and distribution deferral. While the stacked deployment of demand response needs to ensure that a resource is not double counted or paid twice for the same service, value stacking would maximize the financial incentives for load-serving entities and customers to participate in demand response programs, while enhancing grid reliability.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Create incentives for load-serving entities to promote demand response programs.</b></p> <p>Regulators can promote rates and tariffs that allow for capitalization of demand response–related costs, shared savings mechanisms, and performance-based rates to encourage load-serving entities to prioritize demand response in their resource planning, thus taking advantage of the relative speed and ease of its deployment compared to infrastructure-based generation resources. Multi-year rate plans can set clear benchmarks for demand response growth and associated revenues.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Transition away from flat volumetric rates.</b></p> <p>At both the retail customer and wholesale load-serving entity levels, rates should incorporate demand charges for transmission and generation capacity. This would provide a clear incentive for load-serving entities to manage their load during peak periods and create opportunities for demand response and efficiency programs that align with customer interests. Regulators and load-serving entities need to accelerate the adoption of time-of-use pricing and real-time pricing to expose customers to the true costs of electricity during periods of high demand.</p>
<ul style="list-style-type: none"> <li>■ Ease</li> <li>■ Impact</li> <li>■ Status</li> </ul>	<p><b>Allow demand response to participate as transmission and distribution resources.</b></p> <p>Another option is to allow demand response to participate in wholesale markets as transmission and distribution assets. By treating demand response as a non-wires alternative, it could benefit from long-term rate recovery mechanisms similar to transmission infrastructure.</p>

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■ Little ease, little impact, or no progress is being made

Source: Energy Systems Integration Group.

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# Gaps, Barriers, and Solutions to Demand Response Participation in Wholesale Markets

**A Report from the Energy Systems Integration Group's  
Distributed Energy Resources Working Group**

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The report is available at <https://www.esig.energy/demand-response-in-wholesale-markets>.

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