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Demand Response and Flexible Energy Demand in a Renewable Grid

WHITEPAPER

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Shifting the Paradigm

Why Demand Flexibility is the New Grid Imperative

Demand Flexibility has emerged as a cornerstone in the evolving operational strategy of the U.S. electric grid, as the penetration of variable renewable sources like solar and wind continues to accelerate. Where once the grid operated under a supply-follows-demand model, today the reverse is increasingly true: demand must adapt to the ebb and flow of renewable generation. Managing electricity consumption—through strategic demand response and flexible load shifting—is now as crucial as planning generation capacity, especially in meeting peak load requirements. The rise of midday solar surplus and evening demand driven by HVAC and EV charging underscores the urgency of aligning demand patterns with supply. Peak Load Management is no longer solely about generation adequacy; it is fundamentally about orchestrating consumption to follow intermittent renewable output.

Investment in new generation and storage assets has surged over the past decade, yet Demand Response remains significantly underutilized. In U.S. wholesale electricity markets, Demand Response capacity reached approximately 33,055 MW in 2023, representing around 6.5 % of peak demand. Although this was a modest absolute increase from 2022 (when it was ~32,920 MW), its share of peak load stayed flat as overall demand rose. Among the seven major ISOs/RTOs—PJM, CAISO, ISONE, NYISO, MISO, ERCOT, and SPP—only a few have approached or surpassed a 10 % threshold in DR participation, and most remain clustered around the 6–7 % average. This plateau highlights a vast and untapped potential for Demand Flexibility to contribute far more significantly to system reliability.

Demand Flexibility empowers consumers across residential, commercial, and industrial sectors to reduce or shift load in response to price signals or operator instructions. These aggregated demand-side actions function as virtual power plants, relieving grid stress during peak periods and reducing reliance on expensive peaking generation. Rather than waiting for capacity events, distributed loads can preemptively participate in grid balancing, offering a nimble and cost-effective complement to traditional supply-side resources.

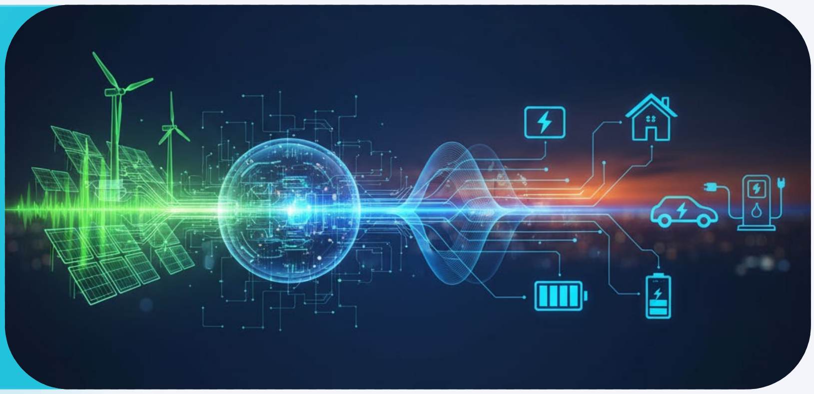
Despite clear benefits, structural barriers have constrained wider adoption. Market fragmentation and inconsistent program rules across ISOs/RTOs pose operational and logistical challenges for aggregators and service providers. The high cost of specialized meters and communication infrastructure—required to participate in wholesale demand response programs—discourages smaller or distributed loads from entering these programs. Moreover, financial incentives for Demand Response often lag behind generation-oriented programs, creating misaligned motivations among utilities, aggregators, and consumers.

With this foundational infrastructure in place, multiple pilot programs and limited-scale initiatives have demonstrated that demand-side resources can reliably deliver peak load reduction, load shifting, and even ancillary services. These results suggest that Demand Response is evolving beyond emergency support toward an operational mainstay that actively partners with renewables to deliver grid value. Success in these pilots indicates strong potential for broader deployment to reduce the need for additional generation assets and to lower long-term system costs.

Taken together, these trends and data underscore that Demand Flexibility must be viewed not as an optional enhancement but as an essential complement to renewable generation. Modern grid reliability hinges on proactive consumption management. Tools like Time-of-Use pricing, automated load control, and aggregated Demand Response resources offer transformative potential. Aligning electricity usage with renewable supply through strategic demand-side interventions can mitigate peak generation requirements, stabilize wholesale prices, and enhance overall system reliability.

Demand Flexibility is becoming vital for U.S. grid operations as renewable energy grows. The grid is shifting from supply-following-demand to demand adapting to variable generation. Although investments in generation and storage have increased, Demand Response remains underused—only about 6.5% of peak demand in 2023—due to market barriers and low incentives. Pilot programs show it can act as a virtual power plant, reducing peak loads and stabilizing the grid. Expanding flexible consumption through tools like Time-of-Use pricing and automated control is key to aligning demand with renewable supply and ensuring grid reliability.

Demand Flexibility is transforming grid operations — shifting from a supply-follows-demand model to one where consumption adapts to renewable generation variability, making demand management as critical as generation planning.



Despite proven benefits, adoption remains limited — with Demand Response participation plateauing around 6-7% of peak demand due to market fragmentation, infrastructure costs, and weak incentives, leaving significant untapped potential for enhancing grid reliability and reducing costs.

ACTION

Tools of the Trade

Demand Response Mechanisms in Action

Within the U.S. wholesale electricity markets, a range of Demand Response mechanisms operates as essential grid-balancing tools. These mechanisms fall into three broad categories based on the services they provide: economic, capacity, and ancillary demand response. Each category offers distinct operational roles, financial structures, participant requirements, and deployment timelines.

Economic Demand Response programs are activated primarily by high wholesale prices. During periods of price spikes—often reaching or exceeding $1,000 per megawatt-hour in markets like ERCOT—load-consuming entities receive financial incentives to reduce consumption, thereby alleviating pressure on spot market pricing. Although these programs enable participants to earn energy payments during high-price intervals, they typically offer lower compensation and carry greater compliance complexity compared to capacity and ancillary programs. Participation depends on flexible load operations and a willingness to respond to sporadic, high-price triggers.

Capacity Demand Response programs play a more structural and planning-oriented role. Regional grid operators forecast peak demand several years in advance (often three years) and procure capacity through auctions in which demand-side resources compete alongside generation. Aggregators work with end-use customers, who agree to curtail a fixed quantity of load when called upon. Participants receive reservation payments for their commitment and additional compensation when dispatched. Event notice windows generally span from 30 minutes to several days, making capacity-based DR more operationally manageable. These programs reinforce grid reliability by reserving demand reductions during critical peak periods without requiring frequent activation.

Ancillary Demand Response addresses real-time grid needs like frequency regulation, contingency reserves, and voltage support. These programs require instantaneous responses—within seconds to a few minutes—because events occur frequently (sometimes daily) and usually last less than an hour. Because of the high value of these services, compensation rates are significantly higher. However, technical prerequisites are strict: participants typically must employ building automation, fast-response controls, and direct communication links to the grid operator or aggregator. These technical demands often limit participation to industrial, commercial, or dedicated behind-the-meter resources capable of automated curtailment.

U.S. wholesale markets fall under the ISO/RTO structure, which includes regional bodies like PJM, CAISO, ISONE, MISO, NYISO, ERCOT, and SPP. Each entity allows demand response to participate in one or more market segments: energy, capacity, and ancillary services. Participation rules vary, but overarching regulations such as FERC Order 745 mandate compensation for demand response dispatched in wholesale markets at the locational marginal price (LMP), provided dispatch is cost-effective. This rule ensures equitable treatment of demand-side resources relative to generation in dispatch economics, subject to a net benefits test to validate value to customers.

Grid operators use two settlement systems: the day-ahead and real-time energy markets. Demand Response Resources (DRRs) typically fall into two types. Type I DRRs are akin to standby capacity offerings, committed ahead of time with set availability. In contrast, Type II DRRs behave similarly to generation resources during dispatch and may participate in multiple service markets simultaneously. Load-modifying resources (LMRs), emergency DR resources, and various curtailment-based offerings fill out the spectrum of program types.

Capacity DR programs integrate into forward-looking resource adequacy planning. Many regions credit the demand-side capacity toward meeting reserve margins. However, because demand response capacity often lacks the same performance certainty as a physical generator, program rules and verification requirements are stringent. Performance penalties, telemetry obligations, and testing ensure that promised load reductions materialize when needed.

On the retail side, utilities have developed Direct Load Control programs that cycle air conditioners, electric water heaters, or pool pumps on and off during peak events in exchange for bill credits. These distribution-level initiatives, often automated via radio switches or WiFi thermostats, have proven effective in shaving peak demand within utility service territories. While traditionally administered by individual utilities, newer models allow these aggregated retail programs to bid into wholesale markets where regulations permit.

Time-of-Use Pricing and Demand Flexibility

Optimal rate design is essential to balance demand flexibility and customer acceptance. Studies suggest that on-peak to off-peak ratios in the range of 2:1 to 4:1 offer effective incentives while maintaining acceptability. Pricing ratios above 5:1 may raise response potential but often deter enrollment unless paired with automated control options.

Retail time-based pricing supports grid reliability and resource adequacy through measurable capacity contributions from responsive customers. Systems that integrate TOU, CPP, EV charging scheduling, thermostat automation, and smart appliance coordination can treat demand-side behavior as virtual capacity. This helps firm renewable generation output, reduce investment in peaking generation, and enhance long-term system cost-effectiveness.

By combining Smart Grid infrastructure—such as advanced meters, real-time communication, and automated control—with thoughtfully designed rate structures and coordinated customer engagement, Time-of-Use pricing becomes a pivotal mechanism for unlocking Demand Flexibility and reducing peak loads. These programs align consumption with cleaner generation windows and provide scalable operational benefits to utilities adapting to a renewable-intensive future.

Time-of-Use pricing with **2:1–4:1 on/off-peak ratios encourages demand flexibility and customer participation. When paired with **smart technologies** and **automation**, it enhances grid reliability, reduces peak demand, and aligns energy use with renewable generation.**

Automation at the Edge

Smart Devices, EVs, and Flexible Loads

The emergence of Smart Grid infrastructure, combined with widespread adoption of advanced devices such as smart thermostats, EV chargers, and behind-the-meter storage, has revolutionized demand-side flexibility. Automated Demand Response (AutoDR) programs enable grid operators and aggregators to send signals directly to participating equipment, triggering preconfigured load adjustments without human intervention. This automated coordination enhances reliability and scalability compared to manual curtailment, thereby strengthening Peak Load Management.

Automated approaches now dominate the Demand Response management landscape. Auto-DR accounts for approximately 59 % of the total DR market, favored by utilities and aggregators for its fast, reliable response. Manual DR—still common in industrial settings—represents the remaining 41 %. In terms of sector distribution, commercial buildings contribute approximately 47% of DR capacity, residential loads about 35%, and industrial facilities the remaining 18%. These figures reflect the increasing applicability of Auto-DR via building automation systems, thermostat controls, and smart appliance integration.

Smart thermostats, programmable communicating thermostats, and home energy management systems provide direct load control pathways. Utility-led programs can remotely reduce HVAC load during peak hours, with minimal discomfort reported by participants. Recent data from one service provider reveals that from 2021 to 2024, demand response events increased by 173 %, while the average enrolled thermostat was triggered only 2 % more often—indicating that events are better targeted and less disruptive. Most participants report that modern DR events are unobtrusive or less unpleasant than anticipated, with 69 % of users expressing comfort with participation.

Vehicle electrification introduces both challenges and opportunities. EV charging is projected to add between 100 TWh and 185 TWh per year to U.S. electricity demand by 2030—around 2.5 % to 4.6 % of total consumption. Unmanaged charging during peak times could exacerbate grid stress, but managed charging enables EVs to serve as flexible loads. TOU pricing, managed charging schemes, and vehicle-to-grid integration (V2G) are critical components of a demand flexibility strategy.

The U.S. Department of Energy has launched the Vehicle Grid Integration (VGI) Initiative to harmonize EV load with grid needs. In 2024, electric vehicle adoption continued to accelerate: electric car sales exceeded 17 million globally, reaching a sales share of more than 20% of new cars. In the United States, EV sales grew by about 10 % year-over-year, accounting for over one in ten new vehicles sold. (By comparison, in 2023, about 1.2 million EVs were sold in the U.S., or roughly 8 % of new light-duty vehicle sales.) DOE anticipates that future EV fleets will serve as controllable assets, delivering grid services such as load shifting and storage, and providing value as aggregated virtual resources.

The scale of smart metering infrastructure supports this automation. By 2023, the U.S. had over 130 million advanced meters installed—about 80% of all electricity meters. This foundation enables real-time communication, remote signaling, and secure telemetry, which are essential for Auto-DR programs. Integrating smart meters with IoT-enabled devices underpins the automated coordination necessary for flexible demand operations. The penetration of AMI technology, combined with ubiquitous connectivity, allows utilities and third-party aggregators to signal millions of distributed devices within seconds. This capability transforms appliances and electric vehicles into a responsive reserve that can be leveraged during grid imbalances.

Significant growth is anticipated in Demand Response management systems (DRMS), which serve as platforms connecting utilities, aggregators, and end devices. The global DRMS market is projected to grow at a compound annual growth rate (CAGR) of 15.8% between 2025 and 2030, reaching nearly USD 26 billion by 2030. Integration with smart grids and automated DR functionalities is the primary growth driver.

On the device side, smart EV charger installations are being supported through utility incentive programs. For example, PG&E offers incentives to EV owners to upgrade home Level 2 chargers to smart" models that can respond to grid signals and shift charging schedules. This kind of load flexibility facilitates dynamic adaptation to grid constraints and renewable output availability.

Artificial intelligence and emerging control frameworks are advancing demand response in EV charging networks. One recent peer-reviewed study proposed an AI-blockchain integrated architecture that achieved nearly 20 % reduction in grid overload during peak periods, with improvements in scalability, reliability, and data protection. Such innovations demonstrate the potential of combining automated control, predictive forecasting, and secure communication to unlock new flexibility pathways.

Nevertheless, challenges remain. Privacy and cybersecurity are significant concerns; nearly 41% of utility executives and 36% of consumers cite data privacy as a major barrier to DR enrollment. Public skepticism regarding data handling by DR platforms must be addressed through robust security design and transparency. In addition, churn in participation remains notable—while about 13 % of U.S. households participate in DR programs, a similar 12 % have dropped out over time. These dynamics underscore the need for clear communication of benefits, minimal disruption, and trustworthy automated systems.

Despite these challenges, aggregated flexible loads—including thermostats, EV chargers, heating systems, smart appliances, and behind-the-meter storage—are increasingly integrated into grid operations. They effectively function as distributed, controllable resources. As the share of renewable generation grows, such demand-side assets play an essential role in aligning consumption with intermittent supply, reducing peak load requirements, and providing ancillary services with minimal incremental infrastructure.

By harnessing Smart Grid technologies, automated device control, and managed EV charging, flexible loads operating at the edge of the grid enable scalable Demand Flexibility. With advanced meters, intelligent buildings, and EV ecosystems integrated through DRMS platforms and incentive architectures, automated demand response becomes a cornerstone of grid modernization and renewable integration.

Virtual Power Plants

The Rise of Aggregated Demand as a Grid Asset

Virtual Power Plants (VPPs) have emerged as advanced orchestrations of distributed energy resources (DERs) that coalesce behind-the-meter assets—such as rooftop solar PV, batteries, EV chargers, and smart thermostats—into a cohesive grid-scale resource. Unlike traditional demand response, which relies solely on load shedding, VPPs enable both demand flexibility and virtual generation. They perform a wide array of grid services ranging from capacity provision to energy shifting and ancillary support, effectively mirroring the operational flexibility of utility-scale generators.

The U.S. currently hosts an estimated 30–60 GW of VPP capacity, primarily rooted in demand response frameworks. Projections indicate that VPP capacity must expand to 80–160 GW by 2030, representing roughly 10–20% of national peak demand, to fully harness its potential as a cost-effective alternative to peaker units. Modeling by the U.S. Department of Energy estimates annual grid cost savings of over $10 billion if this expansion occurs as anticipated. That scaling trajectory positions VPPs as a cornerstone of Peak Load Management in a renewable-rich grid future.

VPP business models vary. In some cases, utilities serve as the resource off-taker, program operator, and customer liaison (as with APS's thermostat program), while in others, third-party aggregators fulfill those roles. Such flexibility allows stakeholders to select models aligned with local regulatory structures and customer engagement strategies.

The technology backbone for VPP operations centers around grid-edge DERMS (Distributed Energy Resource Management System) platforms. These systems aggregate communicating DERs, enabling unified control, forecasting, and dispatch across diverse customer devices. AI-enabled orchestration, predictive analytics, and secure telemetry underpin effective load management. When properly deployed, VPP systems can dynamically shift demand, discharge storage, and even export customer-generated clean energy to the grid, amplifying both operational reliability and renewable integration.

VPPs also strengthen grid resilience in the face of extreme weather. Distributed assets make localized outages less disruptive; communities with behind-the-meter storage and solar can sustain essential power even during centralized system interruptions. Such resilience complements the deployment of demand flexibility strategies, especially in regions prone to heat waves, storms, and transmission constraints.

Finally, the modular nature of VPPs supports adaptive adoption. Utilities and regulators can incrementally grow programs in response to increasing system stress, DER adoption, and EV penetration. VPPs offer option value: operators can ramp participation up or down based on demand growth without the risk of stranded infrastructure investments. This dynamic scalability makes them a uniquely adaptable resource in a rapidly changing energy system.

Taken together, Virtual Power Plants represent a transformative shift in how demand flexibility interplays with generation. They are not only demand-side tools but hybrid resources capable of delivering controllable, grid-scale services. As U.S. markets evolve and DER adoption accelerates, VPPs stand to unlock substantial cost savings, reliability improvements, and operational efficiencies critical to renewable grid integration.

Automation and Smart Devices Drive Demand Flexibility: The widespread use of smart thermostats, EV chargers, and automated demand response (Auto-DR) programs enables real-time, scalable load management—improving grid reliability and reducing peak demand with minimal user disruption.

EVs and Smart Infrastructure Expand Grid Integration: Managed EV charging, V2G technology, and smart metering infrastructure transform vehicles and connected devices into controllable grid assets, supporting renewable integration and powering the growing demand response ecosystem.

CASE STUDIES

Grid-Interactive Efficient Buildings (GEBs) Pilot

DOE and Building Automation

The Grid-Interactive Efficient Buildings (GEBs) pilot, spearheaded by the U.S. Department of Energy, showcases demand flexibility within commercial and institutional buildings equipped with advanced controls and distributed energy resources. In selected federal campuses and large facilities, buildings were retrofitted with IoT-enabled sensors, smart HVAC controls, thermal energy storage, and hybrid centralized–decentralized control architectures. These systems enabled dispatchers to issue load management commands while preserving network stability and occupant comfort. During pilot operations, building energy management systems dynamically adjusted HVAC, lighting, and ancillary loads to shift demand based on grid signals. These orchestrated strategies enabled peak clipping, load shifting, and curtailable capacity delivery with negligible impact on ambient conditions. Simulations and onsite measurements indicated that DER-enabled GEBs could provide demand flexibility services valued in the low hundreds of dollars per kilowatt of enabled capacity—creating a robust financial justification for the control and storage investments. Occupant surveys and operational feedback confirmed that comfort levels were maintained across demand events. Even during extended load-shift intervals, indoor climate metrics remained within accepted standards, suggesting high potential for occupant-tolerant flexibility in commercial settings. By integrating smart metering, automation, and communication platforms, existing buildings became dispatchable grid assets capable of participating in demand response markets. The GEB pilots emphasize the scalability of technology across campus-level portfolios. Because HVAC systems, lighting, and thermal storage can be centrally managed across multiple buildings, the architecture offers an opportunity for scalable demand flexibility without requiring distributed DER investments at every site. The hybrid control approach ensures both local autonomy and centralized coordination, enabling a reliable response without overburdening any single control system. Operational insights include the need for robust baseline modeling and event valuation protocols, accurate measurement and verification, integration with O&M schedules, and strong cybersecurity.

Making Markets Work

Policy & Regulatory Frameworks that Enable Flexibility

Federal and state policy developments over the past fifteen years have fundamentally shaped the landscape for Demand Response and Demand Flexibility in the U.S. wholesale market structure. Pivotal federal actions include FERC Orders 745 and 2222, which have sought to place demand-side resources on equal footing with generation and to open markets to aggregated distributed energy resources.

Order 745, initially issued in 2011 and upheld by the U.S. Supreme Court in 2016, mandated that demand response resources participating in organized wholesale energy markets be compensated at the full locational marginal price (LMP), provided that dispatch yields net benefits and is cost-effective for consumers. This rule established the principle that curtailing load provides equivalent economic service to generation in the dispatch stack. It also introduced a required net benefits test to prevent overcompensation of demand-side resources. By aligning compensation with grid economics, Order 745 enabled aggregators and utilities to make longer-term investments in demand-side infrastructure and participation. Order 719, issued in 2008, further opened markets to demand response by eliminating several participation barriers and establishing opt-out provisions for states. Combined, Orders 719 and 745 laid the foundation for wholesale-level recognition of Demand Response as a resource.

In September 2020, FERC issued Order 2222, which removed longstanding barriers that prevented aggregations of distributed energy resources (DERs), including demand response, from participating fully in RTO/ISO markets. Order 2222 requires each RTO and ISO to permit DER aggregators as market participants and to allow heterogeneous DER aggregations to meet eligibility requirements, even if they are composed of diverse devices like smart thermostats, batteries, EV chargers, or water heaters. While not superseding Order 745, Order 2222 extended participation opportunities by redefining DER aggregation rules, minimum size thresholds, locational constraints, and coordination procedures with host utilities. RTO compliance plans vary in timeline: CAISO implemented its Order 2222 provisions by late 2024, while MISO is proceeding with a two-phase rollout concluding around 2029–30. With Order 2222 fully in force, both retail and wholesale markets can integrate Demand Flexibility at scale.

At the state level, regulatory developments play a vital role in shaping retail tariff design, incentive programs, and aggregated DER participation. The Energy Policy Act of 2005 directed the Department of Energy to promote time-based pricing and eliminate unnecessary barriers to

Demand Response adoption through education, pilot programs, and regulatory coordination. States have responded with varied frameworks supporting TOU tariffs, direct load control programs, and peak-time rebate offerings. In several states, utilities are required to incorporate demand-side performance into integrated resource planning and procurement. Requirements for nondiscriminatory interconnection procedures and value-based compensation have begun to standardize market structures. Evolving market rules are beginning to recognize the aggregate capacity of DER portfolios, and several ISOs have introduced or expanded fast frequency response products that reward sub-second reactions, an area where aggregated battery and demand resources excel. Pilot programs in PJM and New York are testing how electric vehicles and residential batteries can provide synchronous reserve or ramping services, potentially paving the way for permanent market products that treat flexible demand on par with traditional supply-side reserves.

Equally important are efforts to standardize measurement and verification for demand-side performance. Industry groups and national laboratories are developing improved baselining methods that fairly credit load reductions and load shifts, ensuring that demand-side resources are compensated accurately for the grid value they deliver. Advances in metering, telemetry, and analytics—bolstered by widespread AMI deployment—are making it possible to quantify performance in near real-time, which builds confidence in dispatching demand-side capacity during critical periods.

In summary, the policy and regulatory landscape is steadily evolving to accommodate and encourage demand flexibility. Federal orders have opened the gates for demand response and DER aggregation in wholesale markets, while state initiatives are cultivating robust retail programs and dynamic pricing. As these frameworks continue to mature, they are laying the groundwork for an electricity system in which flexible demand is a fully integrated and indispensable resource, enhancing reliability and enabling deeper renewable energy penetration.

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