The Hidden Value of Flexibility: Benefit Stacking Opportunities for C&I Customers Across Market Structures

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ABSTRACT

Electrifying commercial and industrial (C&I) processes is key to deep decarbonization, yet high electricity costs and rigid tariffs can undermine the project's economic viability, in vertically integrated and restructured markets. This paper presents a strategic approach: demand management plans that empower C&I stakeholders to shape electricity demand and unlock multiple value streams. These plans extend beyond load shifting to include process optimization, temporary curtailment of non-essential end-uses, integrated controls, and behind-the-meter resource dispatch. When coordinated, they allow participation in utility programs, capacity markets, and dynamic pricing schemes. While curtailment service providers traditionally support customers' access demand response, this paper focuses on normalizing a broader process that generates revenue, supports deeper electrification, and enhances grid services and reliability.

Central to this strategy is benefit stacking: the ability to layer savings and revenues across rate structures and market mechanisms. For example, a facility might simultaneously reduce demand charges, earn incentives for grid support, and capitalize on wholesale price volatility, seamlessly, all while keeping focus on core business operations. This multidimensional value creation can improve the financial viability of electrification. Rather than treating demand flexibility as a single-purpose tool, we explore its potential as a portfolio of monetizable services for commercial and industrial customers. Through case studies and market analysis, we identify technical and operational enablers that support benefit stacking in both regulated and restructured environments. Ultimately, we demonstrate how coordinated flexibility not only strengthens the business case for electrification but also contributes to grid reliability and system efficiency.

Introduction

Electrification of commercial and industrial (C&I) processes is emerging as a strategy for deep decarbonization, yet its widespread adoption remains constrained by cost and complexity. In many jurisdictions, high electricity prices, inflexible tariffs, and misaligned market signals erode the business case for replacing fossil-fueled equipment with electric alternatives (Baldwin et. al. 2025, McMillan et. al. 2018). At the same time, power systems are undergoing rapid transformation, with increasing shares of variable renewable generation, growing congestion on transmission and distribution networks, and a heightened need for flexible resources that can respond dynamically to system conditions. In this context, C&I consumers hold significant untapped potential to provide demand flexibility as an active, controllable resource (Neukomm et. Al. 2021).

Demand flexibility in C&I settings encompasses a spectrum of capabilities, ranging from simple load shifting to sophisticated orchestration of processes, controls, and behind-the-meter assets. Rather than relying solely on one-off demand reduction activities to respond to utility led demand response requests, C&I facilities can deploy integrated demand management plans to shape electricity needs, for example by optimizing industrial processes optimization, temporary curtail non-critical loads, activate building and process controls, deploy energy storage and other on-site generation, and other distributed energy resources (DER) (Johnson et. al 2024). When these capabilities are coordinated across time and market mechanisms, they can unlock multiple value streams: reducing volumetric energy costs and demand charges, accessing performance-based demand response programs, participating in capacity and ancillary services markets, and engaging with dynamic retail tariffs or wholesale price signals. This concept of benefit stacking reframes flexibility as a portfolio of monetizable services, rather than a single-purpose tool. Frameworks such as the National Standard Practice Manual for Distributed Energy Resources emphasize the importance of capturing multiple, stacked benefits across energy, capacity, reliability, and environmental dimensions when evaluating DER investments (NESP 2020).

The value and feasibility of these stacked benefits differ across customer segments. For C&I electrification, the implications are substantial compared to other customer segments. C&I customers typically face more complex tariffs compared to residential, creating stronger incentives for load management (Murphy et al. 2024; Siano 2014). C&I loads are larger and more dispatchable enabling easier participation in markets with participation thresholds (Alstone et al. 2017; Williams et al. 2023; FERC 2020). By strategically stacking benefits across utility programs, rate structures, and wholesale market opportunities, demand flexibility can improve the net economics of electrification investments, offsetting increased electric consumption with new savings and revenues (Oxenaar and Butler 2026). In both vertically integrated[1] and restructured markets[2], such strategies can reduce operational costs, shorten payback periods, and mitigate exposure to price volatility, thereby making capital-intensive electrification projects more financeable and attractive to corporate decision-makers.

Coordinated C&I flexibility can enhance grid reliability and resilience, support local network constraints, and facilitate higher penetrations of renewable generation, aligning customer-level economics with system-level decarbonization objectives. This paper examines the multidimensional value of demand flexibility for C&I customers and explores how benefit stacking across market structures can improve the economics of electrification and generate unexpected revenue, by situating the C&I demand flexibility opportunity within current policy, regulatory, and market contexts, and highlighting key barriers that limit its deployment across jurisdictions. Through case studies and scenario analysis, we also demonstrate how C&I customers benefit from developing integrated demand management strategies to generate multidimensional value, improve the financial viability of electrification projects, and deliver grid services.

Background and Context

Demand response (DR) refers to programs in which electricity customers adjust their consumption, most often by reducing load during periods of high prices, grid stress, or emergencies to support reliability and lower system costs (Alstone 2017**).** Early DR relied on

[1] Where utilities control generation, transmission, and distribution

[2] Markets with competitive generation and regulated transmission and distribution

manual interventions, such as interruptible tariffs for large C&I customers or one-way load-control devices for residential end uses, with notifications typically issued day-ahead or hours-ahead and limited to no real-time feedback on performance (Siano 2014). As grid needs have shifted with rising variable renewable generation and digital controls, the field has evolved from event-based shedding toward demand flexibility to a broader suite of services that includes shaping (altering load profiles over time), shifting (moving energy use to lower-cost or lower-carbon periods), shedding (reducing total load), and fast modulation ("shimmy") to provide ancillary services shown in Figure 1. (Alstone 2017). This modern approach to load control is enabled by advanced communications, automation, and distributed energy resources that allow customer systems to respond in near real time to grid signals. Most importantly, this evolution towards more dynamic load management created opportunities for customers to stack multiple benefits for electrification initiatives.

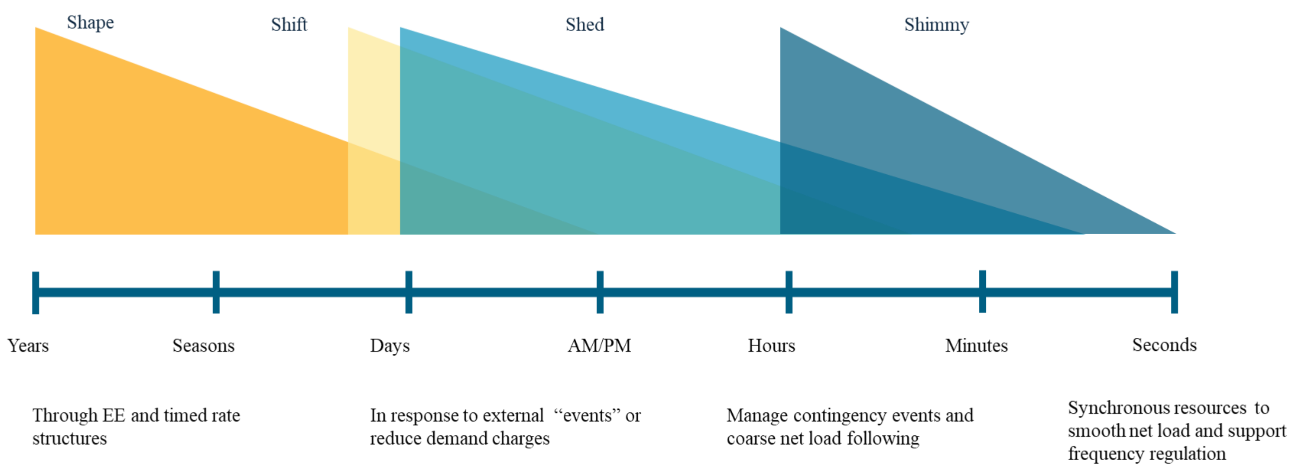

Figure 1. Demand response services across time scales. Source: Alstone et al. (2017)

The C&I sector represents a substantial share of total electricity consumption, accounting for about 60% of US electricity and includes many large, controllable loads offering significant flexible load potential, making them central to electrification and decarbonization goals. C&I customers sometimes have onsite renewables, energy storage, smart controls and automation, and flexible industrial processes[3], which can be orchestrated to reduce the customer's energy consumption, with limited impact on business operations. At scale, these strategies enable significant and reliable load adjustments (Yasmin et al. 2024).

Benefit Stacking for Commercial and Industrial Customers

Demand flexibility offers a wide range of potential benefits for C&I customers, transforming energy use from a passive cost center into a strategic operational asset. As grid modernization advances and regulatory frameworks evolve, customers are increasingly positioned to monetize their ability to flex consumption, enhance operational reliability, reduce

[3] The demand shifting potential of a load can be determined by the ratio between peak demand and baseload demand of an industrial facility, which documents the potential for flexibility of a given facility. Other examples include the methodology proposed by Yasmin et al. (2024). In general, customers flex process load by temporarily shifting operational schedules or temporarily cycling equipment.

electricity costs, and contribute to decarbonization goals. This is the central concept of benefit stacking discussed in this paper: the ability to capture multiple value streams, across utility programs, retail rate structures, and wholesale markets either simultaneously or in sequence.

For most C&I customers, however, direct participation in wholesale markets is impractical due to the expertise, administrative burden, and operational infrastructure required. Curtailment service providers (CSPs) and distributed energy resource (DER) aggregators therefore play a critical role by managing enrollment, tracking baselines, coordinating dispatch, and on behalf of customers. CSPs are third-party providers that manage customer load curtailment for demand response program participation, primarily in response to dispatch events. DER aggregators coordinate a broader portfolio of distributed resources (e.g., load, storage, generation) to deliver multiple grid services across market contexts; thus, CSPs can be viewed as a subset or specialized form of aggregation focused on curtailment. CSPs can aggregate diverse demand resources, that vary in magnitude, location, technology and operational flexibility, into coherent portfolios that meet minimum performance requirements. Real value depends on market design, the granularity of price signals, and the regulatory context that shapes their interactions with distribution utilities (Burger et al. 2017). In general, CSPs and aggregators support customers by identifying cost-effective demand response opportunities, that minimize business disruption, and by helping them leverage or stack the corresponding DR pathways available in their territory. Figure 2 illustrates potential demand flexibility value-stacking opportunities for C&I customers, which are described in detail in the sections below.

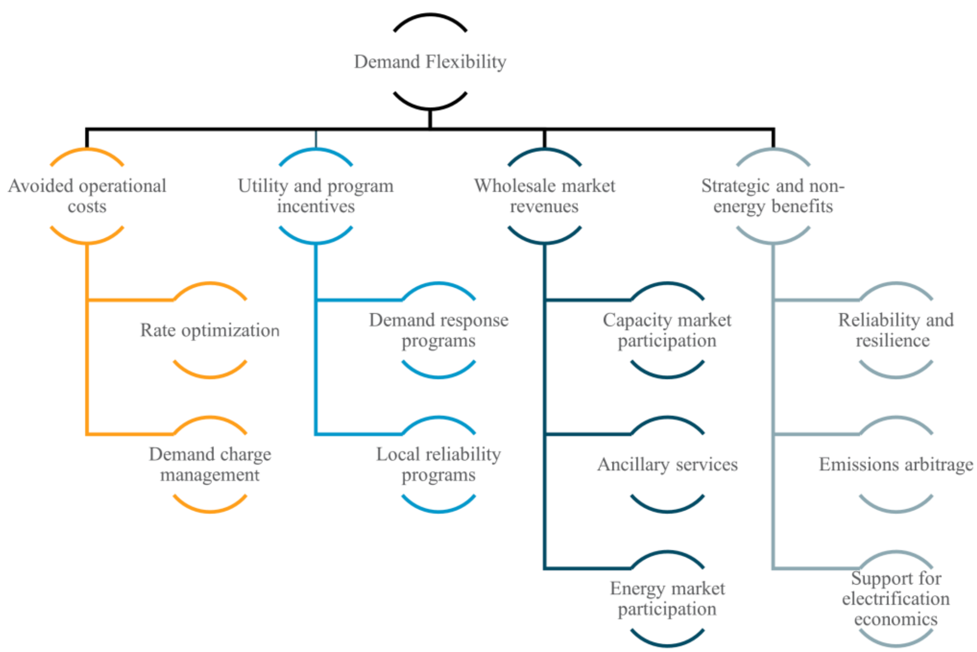

Figure 2. Demand response potential benefit stacking for commercial and industrial customer

Avoided Operational Costs

Avoided operation costs through behind the meter tariff optimization is a foundational benefit for demand flexibility. Demand flexibility offers commercial and industrial customers a powerful tool to manage and reduce their utility bills. For example, demand flexibility enables customers to shift or shed load during periods of high electricity prices if under a time-of-use or dynamic pricing rates. This strategic load management helps avoid on-peak energy charges and aligns consumption with more favorable pricing intervals (Alstone et al. 2017). Many utilize their building management systems (BMS) or other supervisory controls to automate controls, enabling intelligent control of HVAC, lighting, and industrial processes based on pre-set optimization strategies. Additionally, customers can leverage behind-the-meter assets such as batteries, thermal energy storage, and electric vehicle fleets to further reduce dependence on the grid and minimize exposure to peak demand charges.

Utility and Program Incentives

Utility DR and DER program incentives provide direct compensation for reducing or shifting load in response to grid needs, creating a value stream distinct from retail bill savings. Commercial and industrial customers participate by leveraging controllable loads and on-site resources, often through contractual commitments to reduce demand during dispatched events. Programs typically compensate participants through performance payments based on the measured reduction in energy use during dispatched events. Compensation structures vary by jurisdiction and program design but commonly reflect system peak conditions, seasonal reliability needs, or emergency events, with incentives provided through riders or bill credits (Murphy et al. 2024). Achieving these benefits requires interval metering, baseline methodologies, and communication infrastructure or aggregator platforms, with response times typically ranging from day-ahead or day-of notification to 30 minutes to several hours depending on program design (FERC 2024). Utility incentives can often be stacked with tariff optimization and, in some cases, wholesale market participation; however, stacking may be constrained by baseline interactions, performance requirements, and rules limiting double counting of load reductions (FERC 2020).

Market-Based Revenues

Wholesale market revenue opportunities are most accessible in electricity markets, where DERs are treated as market resources capable of providing energy, capacity, and ancillary services. C&I customers typically participate through aggregators, who manage bidding, dispatch, and settlement while enabling smaller or distributed resources to meet market requirements (Burger et al. 2017). Mechanisms include capacity market participation, where customers are compensated for availability during system peaks; ancillary services, such as frequency regulation and reserves; and energy market arbitrage, which captures value from temporal price variation. These opportunities require more advanced technical capabilities, including real-time telemetry, automated controls, and reliable communications infrastructure. Response times vary by service, ranging from day-ahead or hourly commitments for capacity and energy markets to seconds or minutes response for ancillary services. While market revenues can be stacked with retail and programmatic benefits, participation is often constrained by market rules, operational complexity, and performance risk, particularly when resources are committed across multiple services (Murphy et al. 2024).

Strategic and Non-Energy Benefits

Beyond direct financial returns, demand flexibility provides important strategic benefits for commercial and industrial (C&I) customers, particularly in reliability, decarbonization, and electrification. Flexible load resources, especially when paired with backup generation or energy storage, can improve facility-level reliability by maintaining critical operations during grid disturbances or outages (Downing et al. 2023). Participation in local reliability programs can further support distribution system stability by addressing feeder-level constraints such as congestion or voltage issues (Murphy et al. 2024). In addition, coordinated control of loads and on-site assets can enhance power quality through services such as voltage support and frequency response, which is particularly valuable for facilities with sensitive equipment or continuous process loads. These benefits are most valuable in mission-critical environments such as data centers, manufacturing, healthcare, and food processing, where operational continuity is essential. Flexible load management also supports decarbonization by enabling customers to align electricity use with periods of high renewable generation. Shifting demand to these periods reduces reliance on carbon-intensive peaking resources and lowers the emissions intensity of consumption (Xu et al 2023). Participation in aggregated programs, such as virtual power plants (VPPs), can further amplify these impacts by coordinating distributed resources to displace fossil-based generation. Technical requirements vary widely depending on the application but often include advanced controls and system integration, with response times ranging from seconds (grid services) to hours or day-ahead (emissions-aware dispatch).

Importantly, demand flexibility can help mitigate cost and emissions impacts associated with electrification, allowing customers to manage increased electric loads from fuel switching or process electrification while maintaining cost control and supporting low-carbon grid operations. These strategic benefits are highly complementary and often enable stacking across all other value streams by expanding available flexibility and improving overall system controllability.

Technology pathways and analytical frameworks to quantify DR benefits

To effectively participate in demand response opportunities and monetize the value of flexing their demand, customers rely on a combination of flexible resources and enabling technologies that support automation, data visibility, operational coordination, and responsive control. Flexible demand side resources include end-use loads and DERs that can shift, shed, or modulate demand in response to grid needs. These resources are complemented by enabling technologies, such as energy management systems, automation platforms, and advanced controls, which provide the visibility, coordination, and dispatch capabilities required to reliably deliver demand response. Response time capabilities vary by equipment. Synchronous assets, defined as loads capable of near-real-time response to control signals (typically within seconds), can respond almost instantaneously, while other resources require longer notification times. Each plays a distinct role helping customers identify stackable flexibility opportunities, respond to grid signals, and deliver specific demand response services. Table 1 summarizes demand side resource examples, provides a brief description of their core functions in supporting demand response, and highlights the types of DR services they can support. Resources are categorized based on the primary DR service they support, and ordered to reflect the relative timescales of impact compared to other resources. This ordering is illustrative rather than prescriptive, as many technologies are capable of operating across a range of response times depending on configuration and use.

Table 1. Commercial and industrial demand technologies and services across impact timescales

Demand Side Management Resources	Description	Supported DR	Impact Timescale
Energy Efficiency	Foundational demand management resource that reduces overall customer demand.	Shape	Years
Electrified Process Loads	Includes pumps, thermal systems, compressed air, and batch processes that can shift or shed load.	Shift/Shed	
On-Site Energy Storage - Thermal	Thermal storage enables longer-duration load shifting by storing thermal energy from technologies such as chillers during low-cost or low-carbon emissions periods, to reduce behind the meter consumption during peaks.	Shift/Shed	
On-Site Generation - renewable resources	Enhances load flexibility by reducing behind the meter consumption. For example, solar can enable load shifting during daylight hours.	Shift/Shed	
EV Fleets – Managed Charging & V2X	EV fleets support load flexibility by shifting charging to low-cost periods, providing vehicle-to-everything (V2X) discharge during peaks, and coordination with on-site generation to optimize charging and energy storage.	Shift/Shed	
Smart Thermostats and Controls for Electrified HVAC	Electrified HVAC such as heat pumps combined with smart controls for pre-heating or cooling during lower grid stress leverage building thermal mass to reduce peak loads.	Shift/Shed	
On-Site Generation - Combined Heat and Power (CHP)	CHP is a reliable generation resource that can provide frequency regulation among other essential services.	Shed/Shimmy	
On-Site Energy Storage – Electrochemical	Electrochemical energy storage can absorb energy when prices or system load is low and rapidly respond to grid signals to discharge during periods of high grid stress.	Shed/Shimmy	
Capacitor banks (providing reactive power to support voltage fluctuations)	Grid synchronous technologies that can automatically respond within seconds to grid conditions. These devices provide fast, autonomous automatic responses	Shimmy	
Synchronous condensers (provide inertia, reactive power and volt/var fluctuation)		Shimmy	
Fast frequency response controls on DERs (advanced solar inverters, wind turbines)		Shimmy	Seconds

Despite the opportunities, to flex load for multiple purposes, identifying which combinations of value streams are additive, which are complementary and which are mutually exclusive due to physical, contractual or regulatory constraints is challenging. A useful organizing framework treats each value stream as a layer in a value stack (Figure 2), with the total economic benefit equal to the sum of accessible layers minus any penalties, forgone revenues, or compliance costs associated with participation. The primary value layers available to C&I customers are: (1) avoided volumetric energy consumption, (2) demand charge reduction, (3) utility incentive payments, (4) capacity market revenues, (5) ancillary service revenues, and (6) avoided costs under dynamic retail pricing.

Interactions and Constraints

Not all layers of the value stack can be accessed simultaneously. Several important interactions and constraints limit the realized benefit, such as:

Difficulties in Establishing a Baseline

Ensuring that consumption was modulated to respond to a specific DR event, and not for other reasons, is a structural issue. Demand response pay-for-performance incentive payments are calculated as the difference between a customer's measured load and a counterfactual "baseline consumption" of what they would have consumed absent the DR event. When a customer participates in multiple programs, establishing a single accurate baseline that does not-double count or incorrectly characterize savings, is challenging. Baselines require sufficient non-event or non-load control days from representative seasons to create a reliable baseline if customers participate in continuous or non-dispatchable incentives, control groups may be required to establish impact estimates.

Energy Efficiency and Demand Response Tradeoffs

The tradeoffs between Energy Efficiency and Demand Response can also complicate baseline setting. Energy efficiency effectively reduces overall energy consumption which shrinks the DR curtailment opportunity. However, the interaction between both may also benefit the electric system (Webb et al. 2019). This creates a tension between efficiency investments and the financial value of demand response programs, and it requires careful sequencing in electrification and load management planning.

Overlapping commitments

Overlapping commitments arise when a customer has agreed to reduce load under multiple programs simultaneously. For example, a customer enrolled in both a utility interruptible tariff and a wholesale capacity resource agreement may face conflicting dispatch instructions during a grid event. Most program rules contain provisions against "double counting" a single load reduction toward multiple compensation streams (FERC 2020). Customers and their aggregators must actively manage commitment calendars and dispatch logic to avoid performance penalties.

Rebound effects

Rebound effects, which are the tendency for loads that have been curtailed to increase above normal levels in the hours following an event, as industrial processes "catch up", can also reduce the net system value of demand response and may affect a customer's performance measurement if not anticipated in the facility's operating plan (Williams et al. 2023).

Illustrative Value Stack: Cold Storage Facility

To demonstrate the quantitative potential of benefit stacking, consider a hypothetical cold-storage warehouse in a restructured market. The facility invests $24,000 to upgrade refrigeration controls hardware and an additional $3,000 to enable aggregator connectivity. This investment in demand flexibility results in thermal storage capability that allows refrigeration compressors to be shifted by 2–4 hours with capacity of 100 kW. Under a standard time-of-use rate, this facility might save approximately $2,500 annually through strategic load shifting. Participation in a utility demand response program could add $100/kW in performance incentives, yielding $10,000 annually for reliable curtailment of 100 kW.

Enrollment in the regional capacity market through an aggregator could provide an additional $4,000 per year in capacity payments. Combined, benefit stacking across these three layers could generate $16,500 in savings a year with a net revenue of $6,000 at the end of the second year. When leveraging all available benefits, the payback period for investment in demand flexibility enablement is 1.6 years. Without time-of-use optimization and wholesale capacity market participation, the payback period increases to almost 3 years. Participating in multiple value streams represents a material improvement in the project economics of a control’s investment (Figure 3). Actual values will vary by ISO region, rate structure, and facility operating characteristics; this example illustrates the improvement on project economics from benefit stacking rather than a projection of cold-storage facility revenue.

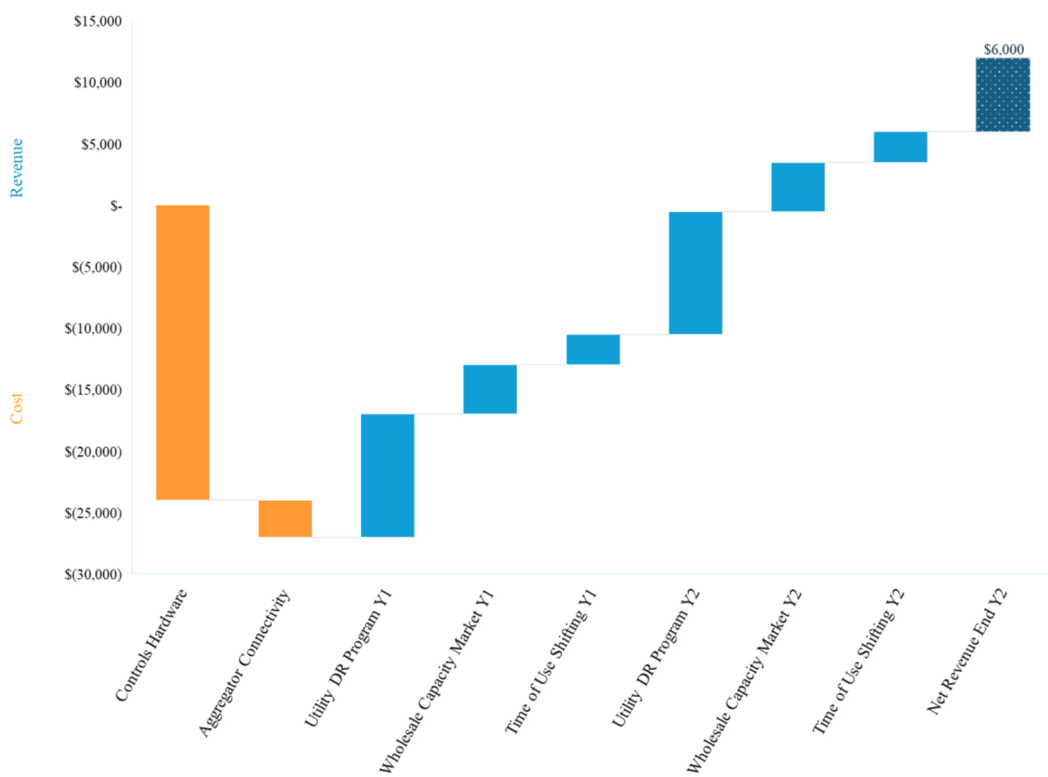

Figure 3. Illustrative example of the cumulative effect of DR enablement costs and potential benefits of DR

Case studies of C&I Customer Demand Flexibility Benefits Across Market Structures

Case study 1: DR Flexibility for Demand Charge Management

Vermont's electric system is vertically integrated, meaning utilities operate regulated monopolies that own or control generation, transmission, and distribution under the oversight of the Vermont Public Utility Commission. Unlike in restructured markets, commercial and industrial customers cannot choose a different electric utility provider; however, they may select among available electric rates and determine whether to participate in demand response programs, making rate strategy a key factor in business economics and operational planning.

This case study features two businesses within Vermont's Green Mountain Power's (GMP) service territory and examines the rate offerings available to them, illustrating how load flexibility can improve electricity affordability. Rate 63/65 is GMP's standard time of use option for medium and large commercial and industrial customers. Under this structure, demand charges are based on the highest 15-minute interval peak during the billing month or 50% of the highest peak in the previous 11 months, encouraging customers to manage and minimize their maximum load. Building on Rate 63/65, GMP's Curtailable Load Rider (CLR) provides additional savings opportunities for customers able to reduce load during system peak events. The CLR is an optional addon that lowers demand charges for participants who can shed at least 25% of their peak load and reliably respond to monthly events. During these curtailment events, a customer's demand sets their monthly on peak demand charge, replacing the traditional weekday peak window with event specific hours and more closely aligning customer costs with GMP's system costs.

The CLR structure is especially advantageous for facilities with flexible and controllable loads that can temporarily reduce or shift major equipment use during system peaks. By curtailing load during these events, participating customers can substantially improve electricity affordability while helping reduce systemwide peak demand. The following examples highlight businesses within GMP's service territory that leveraged the CLR to enhance cost savings by integrating load flexibility into their operations.

Efficiency Vermont worked with GMP and a large industrial customer to explore the CLR as a potential cost saving strategy. Efficiency Vermont conducted real time analysis during the session, demonstrating that the customer could save approximately $400,000 per year by switching to the CLR structure. Motivated by this insight, the customer enrolled in the CLR and now reduces their electricity costs by roughly $40,000 each month.

A second example comes from a public school that added a new chiller system, increasing its demand by 225 kW and raising concerns about both monthly demand charges and long-term ratchet effects. Because the school was already enrolled in the CLR, unmanaged operation of the new equipment risked significantly higher costs during peak events. Efficiency Vermont Engineering Consultants worked closely with the school to develop and refine control strategies that minimized the chiller's contribution to peak demand. These adjustments helped the school maintain the financial benefits of participating in the CLR while integrating new load in a way that avoided unnecessary cost impacts.

Case study 2: Restructured Market with Wholesale Participation

New York's restructured market creates unique opportunities for C&I customers to monetize flexibility through multiple pathways. The New York Independent System Operator (NYISO) manages several demand response programs that C&I customers can access either directly or through aggregators.

Within the NYISO service territory, a university partnership with an aggregator illustrates how a large campus can stack multiple layers of economic value by participating in a diverse set of NYISO and utility programs. The aggregator's automated VPP system enabled the university to reduce energy usage during high-cost and carbon intensive times. The aggregator enrolled the university in NYISO's Special Case Resources (SCR), a program that enables C&I customers to provide capacity services, earning monthly capacity payments plus energy payments when dispatched during reliability events (Murphy et al. 2024). In addition, the university enrolled in utility demand response programs - Commercial System Relief Program (CSRP) and Distribution Load Relief Program (DLRP). This multi-program enrollment allowed the university to accumulate benefits from several compensation streams while also reducing total electricity consumption by 22% and generating $2 million in cost savings in one year, all of which could be reinvested into additional sustainability improvements (McEnany et al. 2025).

This case demonstrates benefit stacking as the university simultaneously lowered energy costs, captured demand flexibility revenue from multiple programs, increased campus resilience, and advanced its emissions reduction goals. Automation made the complex process of participating in multiple overlapping programs simple, while the university leveraged its existing infrastructure to deliver grid support without compromising comfort or operations.

Case study 3: Reliability, Resilience, and Grid Services

Texas's ERCOT system is experiencing rapid growth in large commercial and industrial (C&I) electricity consumption, particularly from data centers and cryptocurrency facilities. As documented in ERCOT's post event report on Winter Storm Fern, ERCOT coordinated directly with these large customers before and during the January 24 to 27, 2026 storm to ensure they were aware of tightening conditions and could adjust operations in ways beneficial to both the grid and their own financial interests (ERCOT 2026). For C&I customers exposed to wholesale or index-based pricing, reducing load during periods of potential scarcity can significantly reduce operational costs. Many such customers have the capability to curtail quickly or shift non-essential processes, allowing them to directly benefit from avoiding elevated market prices while also helping balance system conditions.

Winter Storm Fern illustrates the financial logic behind these responses. Although forecasts suggested a risk of high real time prices due to extreme cold and possible generator outages, ERCOT maintained normal operations throughout the event. This was supported by improved weatherization, earlier and more flexible system operations, and higher reserve levels, but also proactive engagement with large customers who had both the incentive and the operational ability to respond if prices began rising (ERCOT 2026). For C&I facilities participating in demand related programs or operating under index linked contracts, the ability to curtail load when conditions tighten can create substantial avoided cost savings. Curtailment also reduces exposure to price volatility, an increasingly valuable risk management tool for facilities operating energy intensive processes such as data centers and crypto mining.

These dynamics highlight how C&I customers can benefit materially from participating in ERCOT's broader operational strategy. As reflected in the post event report, ERCOT's outreach included large loads because their actions can meaningfully influence peak conditions, but the benefits to customers are equally important: lowering electricity costs, protecting equipment from thermal stress during extreme weather, and improving long term operational resilience (ERCOT 2026). The January 2026 event demonstrates that when C&I customers respond to grid signals, they not only support system reliability but also realize direct economic gains. As ERCOT integrates an increasing number of these large, flexible loads, the financial incentives available to C&I customers will continue to shape both grid performance and customer participation in future demand management strategies.

Case study 4: Decarbonization and Demand Flexibility

The impact of load shifting in GHG emissions depends on the electricity system's hourly generation mix. However, as electricity generation shifts away from fossil fuels, shifting consumption to periods of the day with a higher penetration of renewable energy, can impact the C&I facility Scope 2 emissions, particularly if carbon accounting shifts to an hourly base (Miller et al. 2022). The intuition that demand response aligned with system peak can generate positive environmental externalities is also discussed by DOE's Liftoff report (Downing et al. 2023). This report discusses how aggregation of C&I resources in virtual power plants (VPP), can provide grid services traditionally supplied by fossil fuel peakers, effectively displacing the need for peaking generations, in some cases. The study projects that deploying 80-160 GW of VPPs by 2030 could reduce overall annual grid costs by $10 billion in the United States. While RMI projects that the load shifting generated by VPP aggregations could avoid 44-59 million metric tons of CO_2 emissions per year, by 2025 (Brehm et al. 2023). Furthermore, alignment with Science Based Targets initiative criteria increasingly requires companies to demonstrate grid interaction strategies. Companies like Google and Amazon have integrated demand flexibility into their net-zero pathways, using it to optimize renewable energy procurement and reduce residual emissions (Google 2025, Xu et al. 2023)

Discussion

The four case studies presented in this paper illustrate that C&I demand flexibility generates value across a wide spectrum of market structures, regulatory environments, and facility types. In Vermont's vertically integrated market, strategic rate design and utility demand response programs, and in particularly GMP's Curtailable Load Rider, enabled large industrial customers to capture tens of thousands of dollars per month in demand charge savings with minimal operational disruption. In New York's restructured market, layered participation in NYISO programs, wholesale capacity markets, and utility demand response creates revenue opportunities that can exceed $500,000 annually for large C&I customers with automated load control capabilities. In ERCOT, index-priced customers demonstrated that proactive demand management during scarcity events delivers both cost avoidance and operational resilience. And across all three markets, demand flexibility supports decarbonization by enabling load alignment with high-renewable periods and reducing reliance on carbon-intensive peaking resources.

A consistent theme across these cases is that the greatest value accrues to customers who treat demand flexibility not as an episodic program enrollment but as an integrated operational strategy, but one that begins at the equipment and process design stage, incorporates automated controls, and is actively managed in relation to market signals and utility programs. The Vermont school and industrial examples are particularly instructive: in both cases, the decision to invest in load control infrastructure and operational protocols was the enabling condition for financial benefit, not an optional add-on.

Benefit stacking introduces complexity for the C&I customer, as one must recognize multiple opportunities, understand the complexities and nuances of utility program rules, contract management, dispatch coordination, performance measurement, and settlement. For smaller C&I customers, this complexity may be prohibitive without a capable aggregator or curtailment service provider. Even for large customers with dedicated energy management staff, managing overlapping commitments, baseline calculations, and conflicting demand response priorities require operational sophistication that is not universally available. There is a real risk that the theoretical value stack identified in market analysis is not fully realizable in practice, particularly for customers new to demand response or in the early stages of electrification. However, in general, stacking demand flexibility value streams can improve project economics by:

- reducing the net operating cost increase associated with switching from fossil-fueled to electric equipment, improving levelized cost comparisons
- shortening payback periods and improving the net present value and internal rate of return calculations used for capital-intensive electrification investments
- reducing exposure to electricity price volatility by providing revenue streams that are partly counter cyclical to energy cost increases, improving project risk profiles

The materiality of these effects varies by sector, facility size, and market structure, and should be assessed on a project-specific basis, but even partial stacking can meaningfully shift the electrification business case for customers facing high demand charges or operating in volatile wholesale markets.

Conclusion and Future Research

Commercial and industrial demand flexibility represents an underutilized asset in the transition to a deeply electrified economy. As this paper has demonstrated, the economic case for electrification can be materially strengthened when C&I customers develop integrated demand management plans that allow them to stack benefits across utility programs, retail tariff structures, and wholesale markets. Central to realizing this value is the practice of benefit stacking, the ability to layer savings and revenues across mechanisms without violating program rules, triggering performance penalties, or creating operational conflicts. The analytical framework presented here identifies the key constraints on stacking, including baseline interactions, overlapping commitments, rebound effects, and double-counting restrictions, and proposes a portfolio approach to managing them.

Several important research gaps remain. Quantitative studies of benefit stacking in specific C&I sectors such as manufacturing, cold storage, data centers, healthcare, and higher education, would help practitioners assess the realistic value potential for their facility type and incentivize participation. Further research on the organizational and decision-making barriers that prevent C&I customers from pursuing demand flexibility, even when it is economically attractive, could inform both program design and customer engagement strategies.

As C&I electrification accelerates, the interaction between electrification-driven load growth and demand response capability also warrants dedicated empirical study to evaluate how flexibility strategies can continue to support the broader electrification business case. Finally, long-term system planning frameworks should more fully account for the distinct attributes of demand response, (automated, process-based, and behavioral), particularly in capacity accreditation procedures, where more accurate treatment would improve both resource adequacy assessments and renewable integration planning.

Ultimately, realizing the hidden value of C&I demand flexibility requires coordination across multiple stakeholders: customers willing to invest in operational flexibility; aggregators capable of translating that flexibility into market value; utilities and ISOs that design programs and rules to enable rather than restrict stacking; and regulators who recognize demand flexibility as a legitimate grid resource, worthy of compensation on par with supply-side alternatives. When these conditions are met, demand flexibility can do more than improve the economics of individual electrification projects. In particular, demand flexibility can transform C&I customers into active, compensated participants in the broader project of grid decarbonization and be recognized as an independent revenue source.

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