Guidehouse

Incentive Mechanisms for Leveraging Demand Flexibility as a Grid Asset

An Implementation Guide for Utilities and Policymakers

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Background and Objectives

Demand flexibility is an increasingly important but underutilized capability for utilities and wholesale market operators to use in balancing electricity supply and demand. The ability of buildings to respond quickly and reliably provides grid operators a highly desirable asset that supports grid reliability, power quality, and low-cost service. Such flexibility increases in importance and value as the integration of inflexible or intermittent generation resources (e.g., solar PV) accelerates.

The U.S. Department of Energy's (DOE's) Building Technologies Office has developed a strategy to support greater use of grid-interactive efficient buildings to "advance the role buildings can play in energy system design, operations, and planning." Developed in support of that effort, this implementation guide seeks to help utilities and policymakers understand the need to create appropriately aligned price signals to incentivize building operations that are beneficial to building owners, utilities, and regulators. This guide:

- Characterizes the demand flexibility ecosystem, including the value proposition for demand flexibility, the relevant operational characteristics, and the goals of the key stakeholders.
- Describes and analyzes the financial incentive mechanisms available via three demand response (DR) options: price-based DR, retail DR, and wholesale DR.
- Illustrates the link between demand flexibility, the goals of each stakeholder involved, and each financial incentive mechanism to provide perspective on approaches for operational planning and contracting.

Utilities and policymakers can implement financial incentive mechanisms via policies, rate designs, and programs that are carefully developed to be appropriate, equitable, inclusive, and adaptable. To be successful, such policies, rates, and programs must be developed based on a detailed understanding of all relevant stakeholders and their respective motivations. As a result, this guide also can provide insights for building owners who seek to make investments in demand-flexible capabilities and operational strategies to gain financial returns.

Table 1 summarizes the intended audiences for this guide and the relevant uses of the guide for each audience.

Table 1. Audience Groups and Uses of This Guide

Target Audience	Guide Uses
Utilities *Primary*	• Understand different financial incentive mechanisms and DR options • Help build underlying strategy for new financial incentives for demand flexibility in buildings
Regulators and policymakers *Primary*	• Build a framework for understanding and justifying support for incentive mechanisms to leverage building demand flexibility as a grid resource • Identify policy and regulatory opportunities to further utilize demand flexibility for grid services

Target Audience	Guide Uses
Building owners (i.e., customers) *Secondary*	• Understand available financial incentive mechanisms that could bring in new revenue • Identify technical and operational considerations to support preparation and implementation of demand-flexible operational plans and agreements

Demand Flexibility Value Proposition

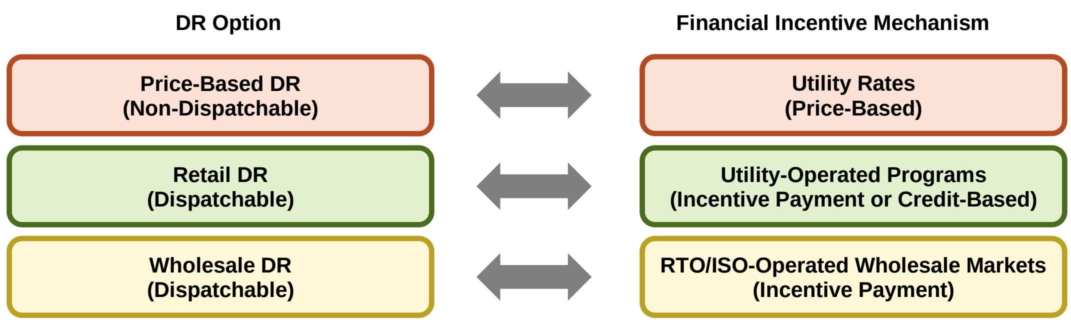
Buildings that can provide demand flexibility, known as grid-interactive efficient buildings (GEBs), are critical resources that offer value in three primary ways:[1]

- **Cost savings:** Reduce operating and fuel costs and defer or eliminate the need for new generation assets and transmission and distribution infrastructure.
- **Reliability and grid flexibility:** Help mitigate reliability issues during emergencies (e.g., short-term generation shortages or severe congestion) and help maintain power quality.
- **Decarbonization and greenhouse gas (GHG) abatement:** Reduce the use of peaking power plants (highest emissions rates) and support expanded use of carbon-free generation.

Incentive Mechanisms

After characterizing the stakeholders and their motivations, this guide describes three DR program and market design options (DR options) and their associated financial incentive mechanisms, as Figure 1 shows. These options are in part distinguished by whether they are dispatchable—that is, whether the building load is curtailed on demand by the program operator or exclusively through decisions by the customer to reduce utility costs. A customer may be involved with all three options at the same time and could respond to signals from both the utility and the regional transmission operator (RTO) or independent system operator (ISO).

Figure 1. DR Options and Financial Incentive Mechanisms



Source: Guidehouse

[1] Read more about GEBs in DOE's Grid-interactive Efficient Buildings Technical Report Series, available at https://www.energy.gov/eere/buildings/grid-interactive-efficient-buildings.

The DR options are as follows:

- **Price-based DR (utility rates):** Utility rates, through their design and pricing, can incentivize specific behavior from customers, enabling them to reduce electric bills while providing value to the utility. Most price-based DR is non-dispatchable.
- **Utility-operated programs (retail DR):** Utility DR programs provide customers with bill credits or off-bill payments when they curtail load for a set period when the utility calls on them to do so or via direct control by the utility. Retail DR is dispatchable.
- **Wholesale markets (wholesale DR):** Customers may enroll in wholesale markets, typically through a third-party aggregator of retail customers. Customers earn revenue from the market operator by curtailing load when called on. Wholesale DR is dispatchable.

Section 3 provides detailed analysis of seven types or approaches for price-based DR, three types of retail DR, and four types of wholesale DR. It characterizes their ability to provide five different demand-side management strategies (efficiency, load shed, load shift, modulate, and generate[2]) and associated barriers and opportunities that utilities and policymakers can address to promote demand flexibility as a low-cost grid resource.

Linking stakeholder goals to the design elements of rates and financial incentive mechanisms is critical to identifying the utility rate and DR programs that will maximize benefits and value capture from demand flexibility. Section 4 synthesizes the stakeholder goals from Section 2 with the characteristics of the financial incentive mechanisms from Section 3.

Ecosystem and Stakeholders

For customers and utilities to realize value from demand flexibility, utilities and policymakers must implement financial incentive mechanisms that align motivations between stakeholders. However, the individual needs of utility customers (i.e., building owners) vary depending on their risk tolerance, so an array of participation options are critical. The first step in developing effective financial incentive mechanisms is to understand the motivations of the relevant stakeholders and their risk tolerance. Table 2 provides an overview of the relevant stakeholders and their key relevant goals.

[2] As described in depth in DOE's GEB Technical Report Series, available at https://www.energy.gov/eere/buildings/grid-interactive-efficient-buildings.

Table 2. Overview of Stakeholder Goal Alignment

Incentive Mechanism-Related Goal	Goal Description Stakeholder →	Regulator	Grid Operator	Utility	Aggregator	Customer	Third-Party Operator	Contractor
Reliability	Protection from grid outages	X	X	X				
High Power Quality	Maintain appropriate voltage or frequency		X					
Resource Adequacy	Sufficient capacity to ensure power availability for peak periods		X					
Cost-Reflective	Align with actual costs incurred to provide utility service	X		X				
Predictability	Consistency and ability to anticipate bill savings				X	X	X	X
Bill/Cost Savings	Customer or utility ability to reduce costs			X	X	X		
Maximize Revenue	Utility opportunity to generate revenue			X			X	
Occupant Satisfaction	Comfort and productivity of people in the building					X	X	X
Payment Structure Satisfaction	Comfort with the way in which bills and payments occur					X		

Source: Guidehouse

Conclusions

This guide builds on the stakeholder and incentive mechanism analyses to identify 11 opportunities (Table 3) for federal, state, and local regulators and policymakers to turn the growth potential into reality for demand flexibility as a grid resource.

Table 3. Opportunities to Improve Access and Value of Demand Flexibility

Financial Incentive Mechanism	Opportunity
Cross-Cutting	1. **All Financial Incentive Mechanisms:** Improved consistency and standardization (see opportunities 5, 6, 7, 8, 9, 10 in this table)
	2. **Rates/Markets:** Progressive state regulations and utility business models focusing on resiliency, reliability, and decarbonization
	3. **Programs/Markets:** Modernization of IT and processes including enrollment, data sharing, and measurement and verification (M&V) to reduce the administrative burden
Rate Structures	4. Alternative/modern rate design
	5. Increased consistency in rate design approaches and structures between utilities (despite necessarily differing prices)
Utility Program Structures	6. Increased consistency in DR program design and implementation between utilities
	7. Increased consistency of regulatory and policy treatment
Market Structures	8. Expanded reach of wholesale markets across the entire US
	9. Unified markets and treatment of distributed energy resources (DER) (e.g., FERC Orders 2222/2222-A); market/service standardization
	10. Elimination of state opt outs and consistent participation enabled across jurisdictions
	11. Regulatory alignment of incentives with utilities to streamline participation

Source: Guidehouse

1. Introduction

1.1 Background

Distributed renewable energy sources such as solar PV and battery energy storage are on a trajectory of rapid growth, and climate change is driving a need for an even more aggressive rollout. Solar PV installed capacity in the US increased from just 4 GW in 2010 to over 90 GW in 2020—an increase of 24 times.[3] In addition, deferred infrastructure investment and increasing electrification of buildings and vehicles serve to increase complexity for grid operators to balance supply and demand while maintaining power quality.

Grid-interactive efficient buildings (GEBs) are receiving increased attention in this context for their ability to offer demand flexibility to provide grid services and reduce customers' energy spend via demand response (DR). Demand flexibility as an asset to grid operators is a decades-old concept that provides multiple benefits for utilities and their customers. The rapid advancement of building technology capabilities, including smart controls and automation, represents an inflection point for buildings to contribute to managing occupant satisfaction and the grid. Increasing use of automation to coordinate building loads, electric vehicle (EV) charging, energy storage, and solar PV power production increases the opportunity to provide grid services and decreases the cost of ownership for building and vehicle owners.

The U.S. Department of Energy's (DOE's) Building Technologies Office has developed a GEB strategy that aims to "advance the role buildings can play in energy system design, operations, and planning." DOE's vision is one of advanced "integration and continual optimization of DERs [distributed energy resources] for the benefit of the buildings' owners, occupants, and the electric grid."[4] To this end, DOE analyzed research and development opportunities in GEB-related technologies and developed a framework to investigate those technologies.[5] In addition, research on customer behavior to characterize customer reactions to rate changes relative to the benefits provided indicates that rate design and other financial incentive mechanisms are a key accelerating factor for customers using their buildings as grid assets.[6]

1.1.1 DR Market

The Federal Energy Regulatory Commission (FERC) reported that US buildings enrolled in utility-operated DR programs already have a peak demand reduction potential of 15.5 GW (8.5 GW in residential and 7.0 GW in commercial, as of 2018) by leveraging demand flexibility. FERC found an additional 30 GW (including buildings and industrial customers) of DR capacity

[3] IEA, "Renewables 2020 Data Explorer," accessed February 2021, available at: https://www.iea.org/articles/renewables-2020-data-explorer?mode=market&region=United+States&product=PV.

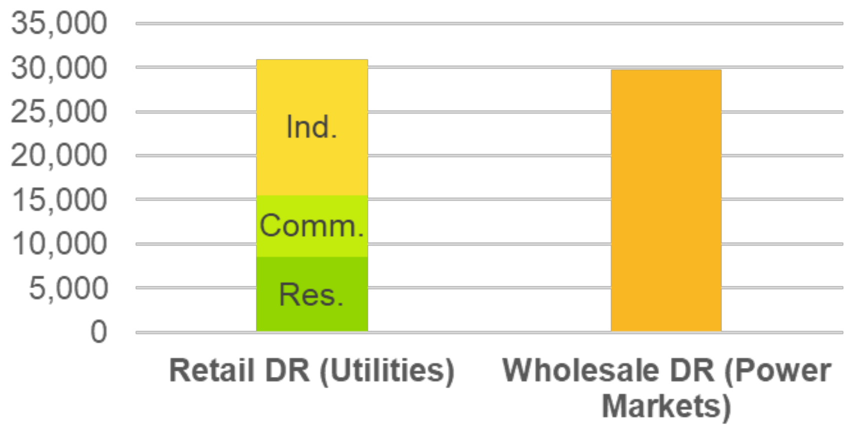
[4] DOE, "Connected Communities Funding Opportunity Announcement (FOA) Number: DE-FOA-0002206," issued October 13, 2020, available at: https://eere-exchange.energy.gov/FileContent.aspx?FileID=d0ccdd3a-15c6-4f11-9e53-0bf53cd2243e.

[5] See DOE's Grid-Interactive Efficient Buildings Technical Report Series, available at https://www.energy.gov/eere/buildings/grid-interactive-efficient-buildings.

[6] Guidehouse, *Building-to-Grid: Industry Transformation for Flexible, Integrated, Value-Generating Resources*, 4Q 2019, p. 20, available at: https://guidehouse.com/insights/energy/2019/building-to-grid.

in wholesale power markets separately and in parallel to utility DR programs (see Figure 1-1).[7] These numbers represent about 5% of the entire peak demand in the US.[8]

Figure 1-1. 2018 Enrolled DR Resource Capacity (MW)



Source: FERC

In some states, regulations and policies undervalue or limit the ability to leverage demand flexibility in buildings as valuable grid assets. State regulators hold substantial power in how the grid operates, and approaches vary widely across the country. Where demand flexibility and DERs are valued by regulators and policymakers, grid operators and utilities are expanding how and where they leverage demand flexibility; this primarily includes regions with wholesale markets and regulators or utilities that support progressive innovation. In other regions, the regulations and policies disincentivize or limit the ability to monetize demand flexibility.

A 2019 study estimated that the DR potential could grow by more than 350% by 2030.[9] The authors found that the opportunities for gains come from modernizing existing DR programs, new demand-flexibility programs to access electrified building loads, and support for "policies, technology standards, regulatory incentives and analytical methods." Utilities and system operators have a tremendous opportunity to promote demand flexibility in buildings as an innovative, local resource to improve grid reliability, reduce system costs, and achieve decarbonization policy goals. To do this, utilities, regulators, and policymakers must determine the right approaches to motivate customers to participate in DR and to adopt equipment, controls, and operational strategies that maximize demand-flexibility value according to the needs of the local grid.

1.1.2 DR Options

This guide focuses on three DR program and market design options (DR options) and their associated financial incentive mechanisms, as Figure 1-2 shows. These options are in part

[7] FERC, *2020 Assessment of Demand Response and Advanced Metering*, December 2020, available at: https://cms.ferc.gov/sites/default/files/2020-12/2020%20Assessment%20of%20Demand%20Response%20and%20Advanced%20Metering_December%202020.pdf. See Table 3-2 for retail DR and Table 3-3 for wholesale DR.

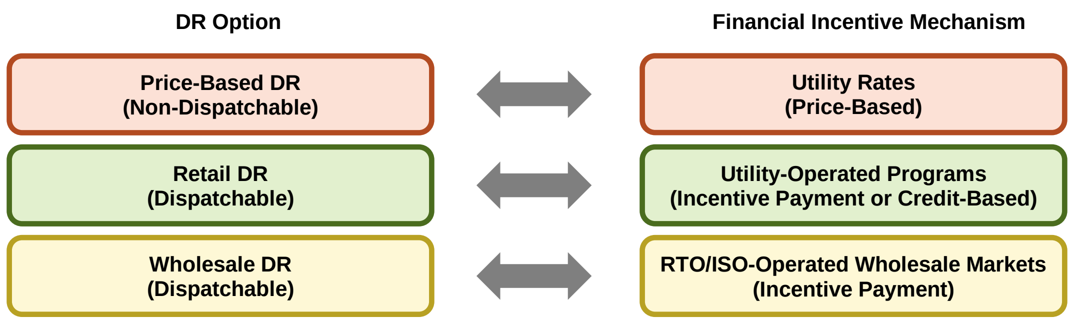
[8] The lower 48 states saw a peak demand of 704 GW in 2019. See: https://www.eia.gov/todayinenergy/detail.php?id=40253.

[9] The Brattle Group, *The National Potential for Load Flexibility: Value and Market Potential Through 2030*, June 2019, available: https://brattlefiles.blob.core.windows.net/files/16639_national_potential_for_load_flexibility_-_final.pdf.

distinguished by whether they are dispatchable—that is, whether the building load is curtailed on demand by the program operator or exclusively through decisions by the customer to reduce utility costs. The DR options include the following:

- **Price-based DR (utility rates):** Utility rates, through their design and pricing, can incentivize specific behavior from customers. When customers optimize their energy consumption relative to the design of the rates, they can reduce electric bills while providing value to the utility. Most price-based DR is non-dispatchable.
- **Utility-operated programs (retail DR):** Utility DR programs provide customers with bill credits or off-bill payments when they curtail load for a set period when the utility calls on them to do so or via direct control by the utility. Retail DR is dispatchable. A common example is direct load control in which the utility remotely curtails air conditioning load by temporarily raising the thermostat setpoint or cycling the air conditioner.
- **Wholesale markets (wholesale DR):** Customers may enroll in wholesale markets operated by a regional transmission operator (RTO) or an independent system operator (ISO), typically through a third-party aggregator (also known as curtailment service providers or aggregators of retail customers). Customers earn revenue from the RTO or ISO market operator by curtailing load when the operator calls on them to do so. Wholesale DR is dispatchable. Markets are structured around the customer providing energy, power, or capacity. A customer may be enrolled in retail DR and wholesale DR at the same time and could respond to signals from both the utility and the RTO or ISO.

Figure 1-2. DR Options and Financial Incentive Mechanisms



Source: Guidehouse

This guide focuses on commercial buildings, though most of the technologies, concepts, stakeholders, incentive mechanisms, and DR options also apply to industrial customers and residential utility customers or homeowners.

1.2 Audience

This guide primarily seeks to serve utilities and policymakers as they consider ways to put in place appropriate, equitable, inclusive, and adaptable policies, rate designs, and programs to incentivize building owners and operators to invest in demand-flexible technologies and operational strategies and to actively participate in demand management and DR. This guide also aims to directly serve commercial building owners and operators seeking to understand today's incentive ecosystem and the changes they could implement to support faster return on investment for demand-flexible technologies or to simply better take advantage of existing programs and markets without additional investments. Table 1-1 summarizes the roles of these stakeholders in the context of demand flexibility and articulates how each of these stakeholders should use this guide.

Table 1-1. Intended Uses for Guide by Each Audience Group (Stakeholder)

Target Stakeholder	Demand-Flexibility Role	Guide Uses
Utilities	• Rate and program designers • Beneficiaries of demand-flexible building services	• Understand how different financial incentive mechanisms via different DR options can maximize demand-flexible capabilities by customers • Help build underlying strategy for the design of new incentives (new rate or program structures) to encourage demand-flexible operation as a grid resource
Regulators and policymakers	• Enablers of consistent and value-based treatment of demand flexibility as a grid resource • Builders of a foundation for optimized financial incentive mechanisms	• Present a framework for understanding and justifying support for the incentive instruments that can enable fair returns on technology investments for demand flexibility • Identify specific opportunities for policy and regulatory change to optimize and expand how demand flexibility in buildings is leveraged for grid services
Building owners (i.e., utility customers)	• Decision makers, operators • Buyers of demand-flexible controls and equipment	• Understand available financial incentive mechanisms that could bring in new revenue or reduce utility bills • Identify technical and operational considerations of using buildings as grid assets to support preparation and implementation of operational plans and agreements

Source: Guidehouse

1.3 Objectives

This guide seeks to help utilities and policymakers understand the need to create appropriately aligned price signals to incentivize behaviors from building owners that are beneficial to those building owners, utilities, and regulators. This guide:

- Characterizes the demand-flexibility ecosystem, including the value proposition for demand flexibility, the associated operational characteristics, and the goals of all the key stakeholders.
- Describes the financial incentive mechanisms available via the three DR options introduced in Figure 1-2 and analyzes them from the perspective of the financial benefit they provide to customers that adopt demand-flexible solutions.[10]
- Illustrates the link between demand flexibility, the goals of each stakeholder involved, and each financial incentive mechanism to help understand the best approaches for operational planning and contracting.

This guide was developed with the following considerations:

[10] GEB capability is used here to refer to the hardware, software, and personnel required to operate a piece of equipment or a set of equipment (including an entire building complex) as a grid-interactive entity. GEB capabilities enable buildings to implement GEB strategies, which are discussed in Section 2.2.

- Utilities may be interested in reducing greenhouse gas (GHG) emissions and reducing costs (and rates) by incentivizing the adoption of technologies to increase demand flexibility.
- Utilities increasingly value demand flexibility due to increased generation variability from renewable sources.
- Utilities have unique drivers and considerations due to local grid and climate conditions, market conditions, regulatory priorities and mandates, and customer preferences.
- The complex mix of circumstances for each utility customer relating to deregulated competition versus vertical integration, state/local/regional climate policy, and the presence of an RTO/ISO, which heavily impact a building owner's ability to monetize equipment investments that enable demand flexibility.

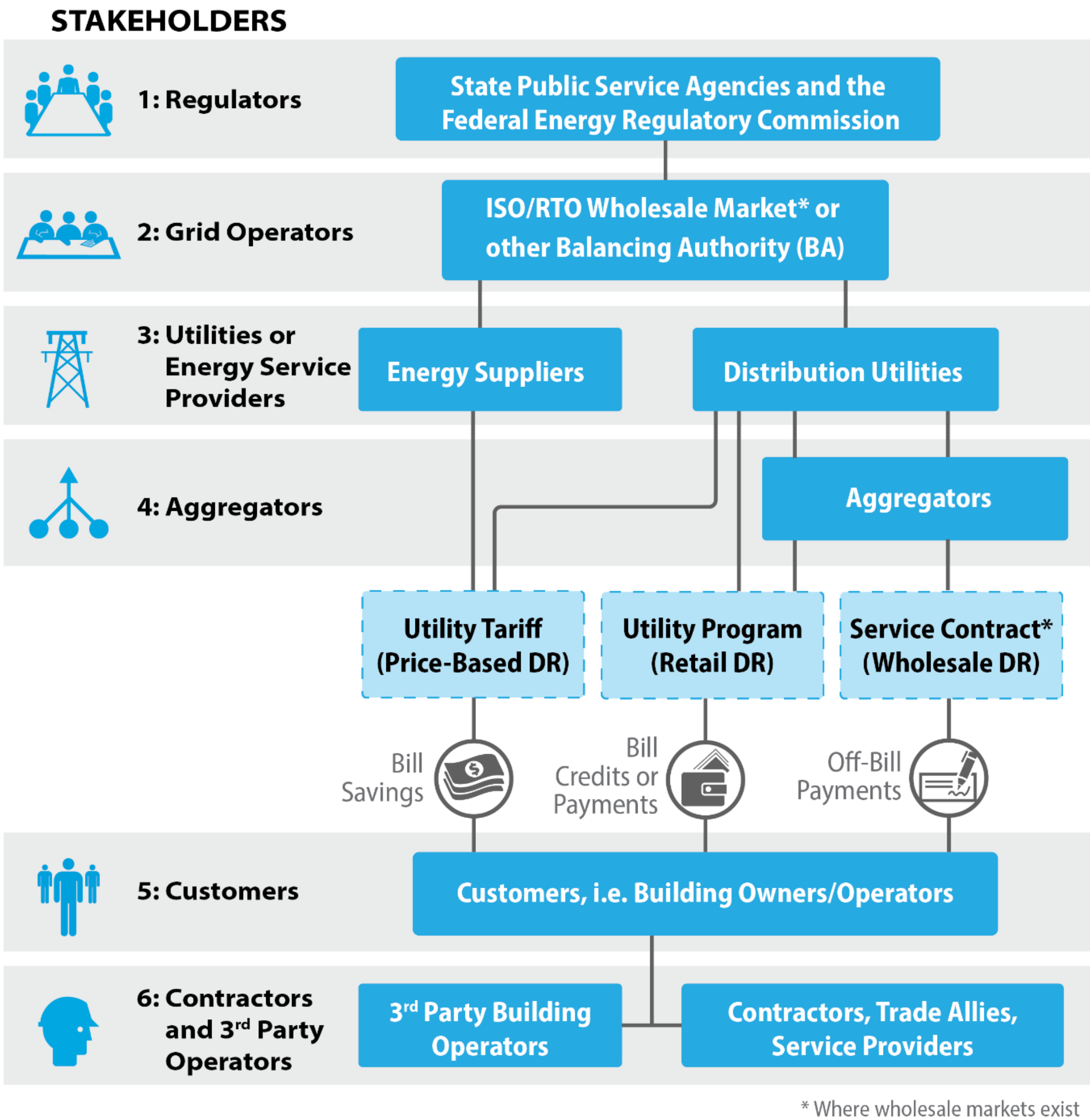
1.4 Operational Ecosystem

Figure 1-3 shows an overview of the ecosystem in which GEBs can operate. This guide focuses on the stakeholders in the ecosystem and the financial mechanisms that connect them. The stakeholders include the following:

- **Stakeholder 1: regulators:** State and federal (FERC) regulators that oversee aspects of rate, program, and market design.
- **Stakeholder 2: grid operators** (balancing authorities): ISOs and RTOs where wholesale markets exist and other balancing authorities (typically vertically integrated utilities) where ISOs or RTOs do not exist, all of which balance supply and demand in a specific portion of the electric grid.[11]
- **Stakeholder 3: utilities:** The utilities enable and manage access to provide demand flexibility to grid operators and are responsible for paying customers for their services.
- **Stakeholder 4: aggregators:** DR aggregators (i.e., aggregators or curtailment service providers) enroll groups of individual customers in wholesale or retail DR to provide firm capacity to the utility or the market. They serve as a provider in addition to utilities and are responsible for paying customers for services.
- **Stakeholder 5: customers** (building owners/operators): The organization or individuals that may provide demand-flexibility services (including advanced services enabled through investment in advanced demand-flexible controls) and seek financial benefits in exchange.
- **Stakeholder 6: contractors and third-party operators:** The organization or individuals that design, install, and manage the building's energy systems for participation in grid services via demand flexibility.

[11] A map of the dozens of balancing authorities in North America is available at: https://www.nerc.com/AboutNERC/keyplayers/Pages/default.aspx.

Figure 1-3. Incentive Ecosystem Overview Covering Six Key Stakeholder Categories



Note: See Section 3.3 for a discussion of where wholesale markets exist in the US.
Source: Guidehouse

This guide is organized around the three primary DR options summarized in Figure 1-2: price-based DR (utility rates), retail DR (utility-operated programs), wholesale DR (RTO/ISO-operated markets). Section 2 describes capabilities and the value proposition for demand-flexible equipment and controls in the context of understanding how to monetize and value demand flexibility. Section 3 examines the DR mechanisms available to building owners and operators (including third-party operators) from various key stakeholder perspectives. Section 4 connects the demand-flexibility concepts and the different incentive mechanisms and how those options align with each stakeholder’s objectives. Section 5 closes with recommendations to all stakeholders on a path forward.

2. Demand-Flexibility Ecosystem

For building owners to optimally monetize demand flexibility where suitable financial incentives exist, they must understand the value proposition, their operational capabilities (based on the technologies available to them), and their own risk profile. This section describes each of these elements individually. This section also characterizes the goals and risk profiles of other relevant stakeholders, which is the basis for the analysis in Section 4 that links demand flexibility with incentive mechanisms.

2.1 Demand Response Value Proposition

All utilities manage reliability while minimizing costs on behalf of their customers. Utilities do this in the face of variability in both customer usage and supply resource availability across the year and on a given day. Resources that have the flexibility to respond at certain times of the day and year are desirable assets. Resource flexibility is increasingly important as the need to integrate inflexible generation sources such as solar PV and other zero marginal cost (price-taking) assets increases.

DR provides a balancing resource for utilities that improves grid reliability and reduces costs relative to other assets. Buildings having advanced communications and control technologies, that enable fast response and reliable dispatch provide even greater value than buildings without those capabilities. Demand flexibility may be viewed as a critical resource in the context of decarbonizing the energy supply and enabling higher penetration of intermittent renewable resources which, on their own, tend to exaggerate ramping requirements when they come on or offline.

DR can offer value in the following ways:

- **Economic value – cost savings:** Utilities can benefit from leveraging DR to reduce operating and fuel costs and by deferring or eliminating the need for new generation resources and transmission and distribution infrastructure.[12] These savings opportunities are in addition to those the customer receives from efficiency or lower energy consumption. Critical cost savings opportunities include:
  – *Deferred or avoided investments in transmission and distribution:* Non-wires alternatives provide peak load relief for localized distribution infrastructure to alleviate grid constraints as a short-term reliability or cost solution, or as a longer-term alternative solution to rate-based infrastructure investments.
  – *Avoided generation capacity costs and better asset utilization:* Demand flexibility reduces the need for peak power generation investments by providing a lower cost alternative (again, where regulators encourage alternatives to rate-based infrastructure investments).
  – *Avoided energy costs including line losses:* Depending on strategic hedging decisions in its supply resource plans, a utility's cost recovery may be limited at peak times, exposing the utility to undesirable financial risk. This risk motivates

[12] The economic benefits can be direct (e.g., fuel savings) and indirect (e.g., increased power quality leading to better grid performance).

demand curtailment in lieu of procuring additional supply at high marginal costs; further, overloaded lines increase line losses, providing secondary value.

- **Economic value – reliability and grid flexibility:** DR helps mitigate reliability issues during emergencies (e.g., short-term generation shortages or severe congestion) and maintain power quality in the grid. These benefits provide economic value and improve system reliability by offering multiple options for a utility to manage variability on the grid.[13]
- **GHG abatement value:** DR can facilitate reduced use of peaking (or marginal) power plants (typically having the highest emissions rates), which helps utilities achieve environmental goals and improve local air quality. In addition, DR supports integration of high levels of carbon-free generation resources, thus abating GHG emissions. DR is uniquely positioned to support and improve the matching of supply and demand (i.e., load following) by eliminating, reducing, or elongating the ramp requirements introduced or exaggerated by large-scale renewable generation going on or offline (e.g., solar at sunset).[14]

These characterizations make no assumptions regarding the interplay between these notions of value. They are structured separately to facilitate transparent strategy development. However, putting a value on carbon and reliability allows value streams to be combined into a single, measurable value.

2.2 Operational Capabilities

In its recent report series, DOE defined five GEB demand-side management strategies (GEB strategies) and the various grid services they can provide.[15] Figure 2-1 shows these GEB strategies; they include:

- **Efficiency:** Ongoing reduction in energy use while providing the same or improved level of building function.
- **Load shed:** Ability to reduce electricity use for a short time and often on short notice. Shedding is typically used during peak demand periods and during emergencies.
- **Load shift:** Ability to change the timing of electricity use. The focus is on intentional, planned load shifting.
- **Modulate:** Ability to balance power supply and demand or reactive power draw or supply autonomously (within seconds to sub-seconds) in response to a grid operator's signal.

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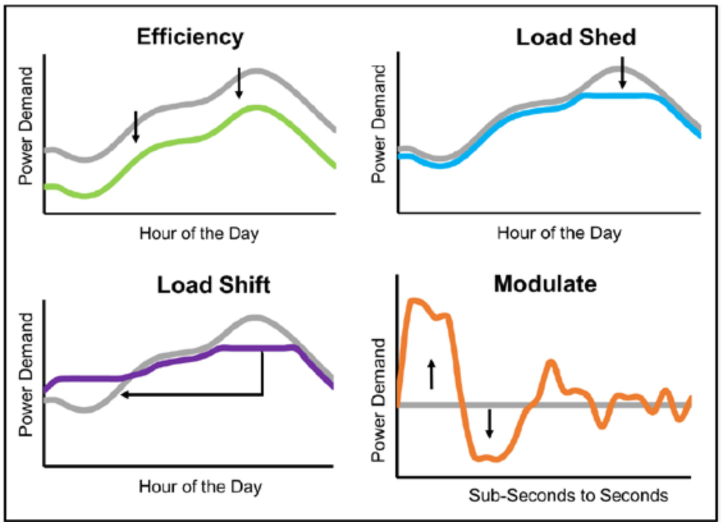
[13] For this discussion, economic value is defined as a net benefit to utilities and customers combined; the specifics of how the value is divided between these parties depends on the regulatory framework, incentives, and rate structures in place.

[14] Only energy-related GHG emissions are considered—that is, the source (power sector) and site emissions associated with operating building equipment and the grid at large. Emissions derived from the manufacture and transport of GEB technologies are not accounted for in this definition.

[15] DOE, *Grid-interactive Efficient Buildings Technical Report Series: Overview of Research Challenges and Gaps*, December 2019, available at https://www1.eere.energy.gov/buildings/pdfs/75470.pdf. GEB strategies are described on p. 12, Table 2.

- **Generate:** Ability to generate electricity behind the meter for onsite consumption or export to the grid upon dispatch from the operator. Batteries are often included here.

Figure 2-1. Four Primary GEB Strategies (Excluding Generation)



Generation omitted from figure as its use varies by equipment type and can provide a wide range of load impacts.
Source: DOE[16]

Each GEB strategy is defined discretely to understand how individual building loads can contribute to overall building flexibility. However, implementation and operational complexity will vary depending on the incentives available to the owner or operator. In today's most common DR programs and markets, buildings must simply reduce load after receiving a signal, in which case the distinction between load shedding or load shifting is irrelevant, as long as enough load is curtailed at the necessary time. Advanced building controls allow building operators to employ a combination of the four primary GEB strategies by optimizing occupant needs and available end-use equipment to provide all these GEB strategies simultaneously and receive the financial benefit from doing so.

Load shedding and shifting can be implemented via fully or semi-automated control or through some level of interaction by an active operator. The Smart Electric Power Association's (SEPA's) *2019 Utility Demand Response Snapshot* found that customer-initiated (i.e., not automatically controlled by the grid operator) programs accounted for 39% of enrolled commercial and industrial (C&I) DR capacity among those utilities surveyed.[17] Initiation can be as simple as electronic approval to begin a shutdown sequence in a building automation system or can require manual shutdown of equipment after receiving email or text notification.

The economic value of demand flexibility generally increases with additional automation and controls. Manual curtailment works well for programs or markets with enough advance notice to operators and relatively few dispatches per year. For more frequently dispatched programs or markets (e.g., modulation from frequency regulation), some level of automation is preferred or required for consistent, reliable performance. Maximum value is achieved by reliable, advanced

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[16] DOE, Overview of Research Challenges and Gaps report, available at https://www1.eere.energy.gov/buildings/pdfs/75470.pdf.

[17] SEPA, *2019 Utility Demand Response Market Snapshot*, September 2019, accessed via: https://sepapower.org/resource/2019-utility-demand-response-market-snapshot/. (see Figure 5 on p. 11).

automation that minimizes the impact on building occupants and enables enrollment in multiple programs or markets, prioritizing those with the highest value.

For additional discussion of GEB strategies, the relevant technologies, and how individual end uses are used for demand flexibility, refer to DOE's GEB Technical Report Series, including both written reports and webinars, available on the DOE website.[18] DOE is also funding additional work to better quantify the demand flexibility of buildings and building end-use equipment.

2.3 Stakeholder Goals and Risk Appetites

Incentives function best when motivations align to promote specific objectives; however, the individual needs of utility customers (i.e., building owners) vary depending on their risk appetite. In this context, risk is a zero-sum game in that risk cannot be eliminated; it can only be moved between different parties via various contract vehicles (e.g., utility tariff). Parties willing to take on more risk may see increased potential upside, but they might also be exposed to higher cost volatility and penalties for underperformance. Parties with lower risk appetites will see consistent but likely lower returns on their demand-flexible technology investments. Examples of how each party manages risk include the following:

- **Utility:** Reduces risk by employing technology solutions to best predict portfolio resource performance and designing rate structures that provide the appropriate financial rewards and penalties.
- **Building operator:** Manages risk by employing technology solutions to increase firmness of building resources and enable maximum and consistent savings when delivering demand-flexible services.

The first step in developing effective financial incentive mechanisms is to understand the motivations of the relevant stakeholders. The following subsections detail the goals and risk appetites for each stakeholder type. While these subsections detail the incentive mechanism goals, other notable goals may also drive decision-making. These other notable goals are identified but not discussed in this guide because they are generally pursued independent of demand flexibility.

2.3.1 Regulators

Incentive Mechanism Goals:	(1) Reliability (2) Cost-reflective rates
Other Notable Goals:	(3) Affordability (4) Safety (5) Achieving local or regional policy objectives

Regulators are responsible for ensuring utilities can support safe and reliable electricity delivery at the lowest cost possible while also considering the policy objectives of their jurisdiction, such as carbon reductions. Regulators include state regulatory authorities (e.g., public utility

[18] DOE GEB website: https://www.energy.gov/eere/buildings/grid-interactive-efficient-buildings

commission or public service commission) that primarily regulate investor-owned utilities, FERC at the federal level, and municipalities for cities and towns that have publicly owned utilities.

With respect to utility rates, regulators are focused on ensuring cost-reflective rates while supporting rate designs that may deviate from costs to enable progress toward policy goals and legislated mandates, where appropriate. Regulators are frequently put in the unenviable position of weighing many stakeholder interests and ultimately having to decide on an outcome that will leave one or more stakeholders unsatisfied.

2.3.2 Grid Operators

Incentive Mechanism Goals:	(1) Reliability (2) Power quality (frequency/voltage) (3) Resource adequacy
Other Notable Goals:	(4) Safety

Grid operators maintain the supply/demand balance across a range of timescales. At one end of the spectrum are minute-by-minute operational decisions for load balancing; at the other end are the decisions supporting resource adequacy and planning for the future. RTOs and ISOs operate grids using the wholesale market, so market design and implementation are critical to their work. Utility grid operators (where RTOs and ISOs do not exist) must conduct resource planning and implementation themselves.

2.3.3 Utilities

Incentive Mechanism Goals:	(1) Reliability (2) Cost-reflective (fair, complete cost recovery) (3) Cost savings (4) Maximize revenue
Other Notable Goals:	(5) Affordability (6) Safety

Utilities are generally focused on three key issues: delivering electricity reliably and safely, keeping electricity affordable for their customers, and ensuring fair and complete cost recovery to include appropriate (high) rates of return for the utilities with investors. As a result, utilities typically look for the least-cost option to ensure reliable and safe electricity delivery to their customers while maximizing revenue. Utilities with a focus on shareholder return, such as investor-owned utilities, have financial incentives to invest in assets to ensure reliability of supply and delivery given they make money by earning a return on capital investments for infrastructure. All these factors can influence how a utility will approach rate design to incentivize buildings for providing grid resources.

2.3.4 Aggregators

Incentive Mechanism Goals:	(1) Maximize revenue (2) Predictable market or program rules
Other Notable Goals:	(3) Operational excellence (low-cost delivery) (4) Predictable or guaranteed revenue for customers via a successful business model

Aggregators' primary goal is to maximize revenue by enrolling customers in wholesale or retail DR and constructing optimal contracts with those customers. An aggregator may provide aggregation services as a:

- **Wholesale DR aggregation provider:** One of many aggregators authorized by an RTO or ISO to enroll in wholesale markets and services.
- **Retail DR aggregation contractor:** Sole aggregator or one of multiple aggregators contracted by the utility to provide a set curtailable capacity (direct customer participation typically not allowed)**.**
- **Retail DR authorized aggregator:** One of many authorized aggregators that facilitates participation but has no fixed contractual capacity to deliver (utility may or may not allow direct customer participation for advanced customers).
- **Retail DR program operator:** Sole organization, typically procured by the utility through a competitive RFP process, contracted to provide DR services for a distribution utility; conceptually akin to an energy efficiency program implementer.

Aggregators are unique among stakeholders in that they operate across jurisdictions, so another key enabler of business growth is consistency between programs or markets, which reduces operational complexity and streamlines new market or program entry. Differences in program and market rules across the US add substantive operational cost for aggregators. Ongoing operational excellence to manage cost for service delivery becomes important as well, which can motivate the development of advanced technologies to maximize customer flexibility at the lowest-possible costs.

2.3.5 Customers (Building Owners or Operators)

Incentive Mechanism Goals:	*Risk-Averse Customer:* (1) Occupant satisfaction (2) Predictable bill savings	*Risk-Taker Customer:* (1) Occupant satisfaction (2) Maximize bill savings
Other Notable Goals:	Varies	Varies

As customers consider investments to reduce and manage their energy spend, they should first focus on energy efficiency and leverage advanced controls to ensure occupant comfort and manage energy costs. Additional advanced control capabilities can then be applied to optimize demand flexibility. The goal is to ensure that occupant comfort and productivity are rarely (if ever) compromised to achieve operational efficiencies and cost savings. In the long run, building owners seek to earn a satisfactory return on their investments in advanced demand-flexible technologies; tenant satisfaction plays a key role in achieving this goal because satisfied tenants remain in the building for longer periods.

Building owners have varying risk appetites for energy-related investments and operations, and their approach to design, installation, ownership or financing, operation, maintenance, and preferred incentives for financial returns vary in kind. This guide considers both ends of the risk appetite spectrum, as Table 2-1 summarizes. Most customers will fall somewhere between the risk-averse and risk-taking customer examples.

Table 2-1. Building Owner Preferences by Customer Energy Spend Profile

	Risk-Averse Customer	Risk-Taking Customer
Incentive Mechanisms	• Predictable, simple utility costs (e.g., subscription rates) and services that require limited involvement for day-to-day operations	• Real-time or similar variable rates with opportunity to maximize cost savings and revenue generation (e.g., energy exports) but with greater downside cost risk
Operations	• Minimal operational variability that could compromise cost savings • Willing to yield control of building operations to an advanced third-party for reduced performance risk and stable rates	• Flexible operationally, taking an active role with the daily operations • Ok with risk-taking to beat the rate through actively managing systems

Source: Guidehouse

Many owners operate their buildings using a combination of onsite and offsite staff (e.g., centralized control center for owners with a large portfolio of buildings) to manage occupant engagement; these staff also ensure equipment is operating properly throughout normal daily or weekly schedules, as well as through any extraordinary conditions (e.g., extreme weather events). In the case of equipment and controls that enable demand flexibility, the owner or operator would support the trade ally after installation for commissioning and to build out and implement the operation plan, taking particular care to account for performance requirements for the relevant DR programs. Those DR programs using automated dispatch would also require the owner or operator to coordinate with the utility or grid operator and other trade allies to support the commissioning and integration of third-party hardware and controls. Such coordination is particularly important for advanced retail or wholesale DR where exporting power is involved, in which case special telemetry or metering may be required.

Some building owners elect to outsource many aspects of project delivery (e.g., design and installation), so considerations for those contractors, service providers, and financiers also carry weight when understanding incentive mechanism effectiveness. Design and installation and operations and maintenance (O&M) are the two most common areas outsourced to third-party providers. Large entities having many buildings or campuses and substantial in-house expertise are most likely to take on substantive portions of this work themselves, but even those building owners rely on contractors for design, build, and operational services.

2.3.6 Third-Party Operators and Other Contractors

Third-party operators and other contractors support building owners by providing equipment and services.

2.3.6.1 Third-Party Operators

Incentive Mechanism Goals:	(1) Occupant and owner satisfaction (2) Predictable revenue (3) Operational efficiency (4) Maximized revenue
Other Notable Goals:	None

Customers may choose to outsource operations of one or more systems to a third party. As with in-house operators, a third-party operator will use a combination of onsite and offsite staff to manage engagement with occupants and ensure equipment is operating properly throughout normal daily or weekly schedules as well as through any extraordinary conditions (e.g., extreme weather events). Third-party operator risk appetites and goals differ somewhat depending on the systems they operate and the contracting terms they have. Contracts often have consistent payment structures that move risk from the owner to the third-party operator, which allows the building owner to enjoy stable, predictable costs and the operator to maximize revenue through energy efficiency and DR (e.g., performance contracts). System types include:

- **Comfort systems** (e.g., HVAC, lighting): Focus is on occupant satisfaction (comfort and productivity) because the operator may be on the receiving end of all occupant complaints and on efficiency, which may be a driving motivation under a performance contract.
- **Non-comfort systems** (e.g., battery energy storage, backup generators, and solar PV): Focus is on operational efficiency and maximizing revenue through DR. Some third-party operators may offer more holistic solutions for risk-averse customers to design, build, finance, own, and operate (or some subset of these items) such systems, providing energy-as-a-service (e.g., under a power purchase agreement) to the customer.

In some cases, the third-party operator may also be the owner of the equipment, in which case the contract with the building owner may be set up as a lease, a power purchase agreement, or an as-a-service (XaaS) model (e.g., efficiency-as-a-service or heat-as-a-service). In such cases, the stakeholder category of third-party operators is blurred with contractors (see Section 2.3.6.2). Customers should carefully analyze these contracts to ensure they align with their risk appetite and to understand to whom the demand-flexibility benefits accrue or that the demand-flexibility benefits do not invalidate energy-saving guarantees. For example, a risk-averse customer may choose an XaaS model with a flat monthly fee, which limits the customer's ability to leverage demand flexibility for increased revenue or utility bill savings.

2.3.6.2 Contractors and Service Providers

Incentive Mechanism Goals:	(1) Owner/occupant satisfaction (minimizing callbacks and supporting long-term quality) (2) Predictability (of cash flows)
Other Notable Goals:	(3) Facilitating business development

Contractors (i.e., trade allies)[19] design and install building equipment, systems, and controls while creating earnings to support ongoing business concerns. Contractors also include other service providers like those who sell software solutions (software-as-a-service), who may also be critical trade allies for enabling and maximizing demand flexibility. These contractors and service providers serve as a critical provider of expertise on products and software. They provide equipment and software commissioning/integration services following initial installation but hand off daily operations to onsite or third-party staff. Additional roles include:

- **Incentive program intermediary:** They serve as a critical connection for many utility efficiency incentive programs. A trade ally's comfort level and experience with a technology will dictate whether they recommend it and whether the customer will have a good experience. Getting trade allies trained on the equipment and supportive of the program is critical to success.
- **Financing of equipment:** Some contractors offer financing and receive their payments over time, with a premium for carrying the financing costs. Financing solutions provide long-term annuities to contractors that grow with more projects and create a steadier flow of revenue. Examples in the market include loans, leases, power purchase agreements, and XaaS models; the specific contractual arrangement dictates how much of the flexibility benefit goes to the customer versus a third party.
- **O&M:** Some contractors also provide O&M services in a more vertically integrated approach to project delivery.

Typically, each contractor is focused on one technical area. For example, a building owner may end up with a trade ally supporting the installation of EV charging, while a different trade ally focuses on HVAC systems and controls. Trade ally business models typically focus on achieving payment for equipment and installation services that include the costs of the equipment plus labor and a return. Contractors generally focus on quick turnaround of costs to revenue, growing their business through the volume of projects in a year. When incentives for these stakeholders are aligned with the goals of the building owner and are clearly articulated in service-level agreements, they are well-positioned to help building owners achieve the benefits of demand-flexible equipment and monetize their value.

3. Effective Incentive Mechanisms for Demand Flexibility

This guide investigates three financial incentive mechanisms for leveraging demand flexibility as a grid resource, each based around a different DR option; these include utility rates, utility-operated programs, and RTO/ISO-operated wholesale markets. Table 3-1 summarizes the key

[19] In this paper, trade allies are those entities that provide planning and installation support for equipment and controls; for larger buildings, this definition can begin to overlap with building operators in cases where the same entity provides contracting for design, build (installation), ownership, operation, and maintenance.

elements of these different incentive mechanisms. While these incentive mechanisms are presented as separate components, the value-stacking potential is an important consideration for customers that may be able to participate in multiple mechanisms concurrently (potentially all three). Technology incentives (e.g., equipment rebates) are part of the broader effort to expand how and where grid services leverage demand flexibility, but they are not included in the scope of this guide.

Fundamentally, the key to success regardless of the incentive mechanism is optimal design and price setting to ensure building operators and owners are motivated to make the investments and take the actions that will benefit grid operators and other stakeholders, improve grid efficiency, and help achieve sustainability goals.

Table 3-1. Overview of DR Options and Associated Financial Incentive Mechanisms

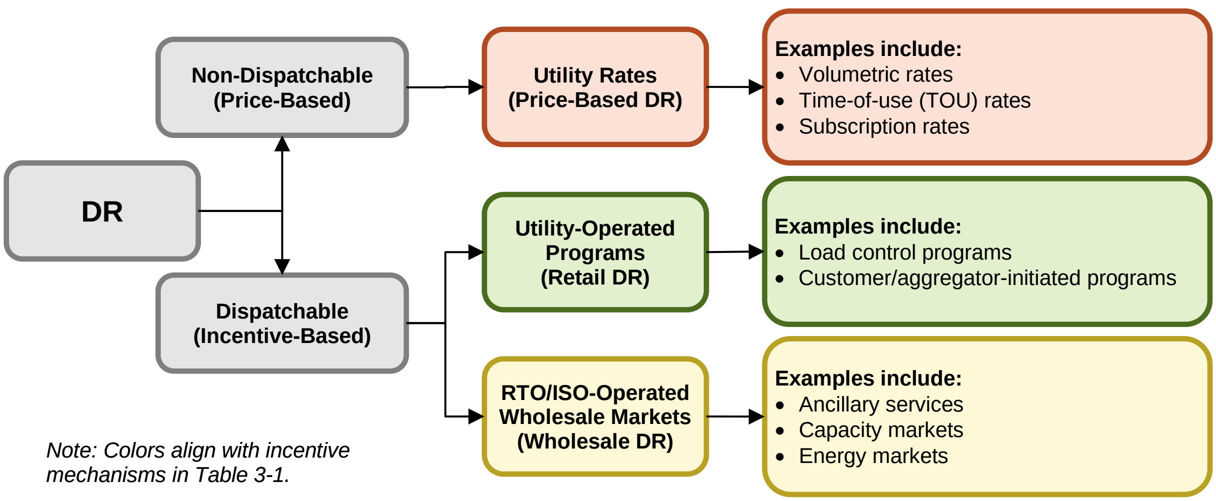
DR Option	Financial Incentive Mechanism
Price-Based DR Load management controls, scheduling, and operational optimization to help customers reduce their own load on a predictable schedule based on their utility rates. ***Operator:*** Building owner or third-party contracted operator ***Applicability:*** All customer segments, with options varying by segment ***Dispatchable:*** No, except for critical peak pricing, where peaks are set on-demand by the utility	**Utility Rates** Utility rates, both the structure (mix of fixed fees and variable fees for kWh or kW, etc.) and the pricing levels, incentivize customers to optimally manage their load at certain times of day or times of year. Critical peak rates include high priced periods defined by the utility as needed. ***Financial compensation:*** Utility bill savings
Retail DR Upon dispatch by the operator (sometimes via an aggregator), customers reduce load using a combination of advanced controls and manual shutoffs; the utility may also automatically curtail load via direct control of the equipment (e.g., AC switch). ***Operator:*** Distribution utility (sometimes via an aggregator) ***Applicability:*** All customer segments, with options varying by segment ***Dispatchable:*** Yes, except for unique cases with upfront incentives (see example following the table)	**Utility-Operated Programs** Distribution utilities can design a program that suits their individual needs and may include performance-based incentives (requiring measurement and verification for payment) or participation-based incentives where the utility controls the equipment. Financial penalties may apply for underperformance in these programs. Behavioral programs also exist that are opt out, have no performance penalties, and typically include no financial incentive. Customers are instead are motivated by data visualization communications and comparisons to performance of other customers. ***Financial compensation:*** Utility bill credits or payments
Wholesale DR Upon dispatch by the operator (via an aggregator), customers reduce load; this may include a combination of advanced controls and manual shutoffs; advanced markets with short notification windows, strict performance requirements, and stiff penalties motivate greater use of automation. ***Operator:*** RTO or ISO, where they exist ***Applicability:*** All customer segments in regions where wholesale markets exist, with options varying by segment and by aggregator ***Dispatchable:*** Yes	**RTO/ISO-Operated Wholesale Markets** Wholesale markets often include multiple individual products or services such as capacity, reserves, and energy for which the RTO or ISO compensates the customer (generally via an aggregator) for curtailing load after notification. Some services, including many reserve programs, include payment for availability even if there is no dispatch and load does not need to be curtailed. Penalties may apply for underperformance. ***Financial compensation:*** Off-bill revenue stream

Source: Guidehouse

Figure 3-1 shows the DR options that are associated with the three incentive mechanisms (colors match those in Table 3-1). However, rates and programs exist that do not fit cleanly into this categorization, and as rate and program design continues to evolve with increasingly creative approaches, the distinct lines between dispatchable and non-dispatchable and between utility rates and utility-operated program categories will continue to blur. Example exceptions to this categorization include:

- **Utility rate example – critical peak pricing (CPP):** CPP rates establish a set, higher price for electricity (per kilowatt-hour, or kWh) consumed during critical grid peaks (typically the hottest summer days). The critical peak periods are not fixed; rather, they are called as needed by the utility, which sends out advance notice akin to dispatching retail or wholesale DR. See Table 3-2 for additional details.
- **Utility program example – non-dispatchable programs incentives:** A program may include an upfront incentive in addition to or instead of the dispatch-based payment. The upfront payment may serve to promote the use of scheduled load management (non-dispatchable) that aligns with grid peak periods. For example, Connecticut Green Bank's proposed Solarize Storage program included an upfront financial incentive for establishing default settings to align with peak periods as well as an upfront incentive for purchasing equipment and performance-based incentives for participation in active dispatches.[20]

Figure 3-1. Taxonomy of DR Options



Source: Guidehouse

3.1 Utility Rates (Price-Based DR)

3.1.1 Overview

Electricity rates are a critical driver of customer behavior and can provide important signals for how customers can manage their utility bills and monetize investments in advanced efficiency or

[20] Solarize Storage: Proposal from the Connecticut Green Bank, Docket No. 17-12.03(RE03), July 31, 2020, available at: https://ctgreenbank.com/wp-content/uploads/2020/08/PURA-Docket-No.-17-12-03RE03-%E2%80%93-Solarize-Storage-Proposal-from-the-Green-Bank.pdf.

flexibility technologies. When utilities design their rates with high levels of transparency, they provide clarity for building owners and operators to see what actions are aligned with which financial signals. Appropriate incentive design within the rate structures can send signals to customers and operators that can translate to better participation and better return on investment for demand-flexible capabilities. These incentives are sometimes referred to as a type of price response, behavioral, or non-dispatchable DR because they operate outside of the communication signal dispatch construct of grid operators. Instead, they provide a fixed framework (though not necessarily fixed rates) for operators to work within every day.

A holistic discussion of rate structures must consider two different sets of charges and rate structures on each customer's electricity bill, including:

- **Distribution charges:** These fees are paid to the local distribution utility (i.e., local distribution company) to fund distribution infrastructure, O&M, policy objectives, etc. The structure of these fees can vary from fixed monthly charges to charges linked to consumption, such as energy (kWh) and demand (kW). Ideally, rates compile different components that are individually listed to indicate their purpose to regulators and customers. Historically, utilities have offered few, if any, rate options to customers for their distribution charges, but that is beginning to change.
- **Supply charges:** These charges are paid to a supplier to cover costs related to generating electricity and moving that electricity to load centers. For vertically integrated utilities where customers have no retail supply choice, the supplier is the same as the distribution utility; where retail competition exists,[21] customers may have numerous options for retail suppliers. Therefore, customers may have more than one choice for rates and rate structures to procure energy supply. Rate options where retail choice is available are substantially broader and more diverse. Like distribution charges, supply rates can vary from fixed to volumetric and can be driven by market dynamics, such as gas prices, and market rules.

Figure 3-2 provides an overview of rate structure considerations for each customer profile. Utilities should consider the differences in customer risk preferences in their rate designs (see Section 2.3.5 for discussion of customer risk profiles related to energy spend and operations).

Figure 3-2. Rate Structure Considerations by Customer Energy Spend Profile

Risk-Averse Customer

- **Preferences:** Minimal exposure to wholesale volatility leads to predictable rates, such as subscription rates in exchange for relinquishing some degree of control to a third-party.
- **Concerns:** Per-kWh energy prices will feel comparatively high; limited availability (currently) of predictable rate choices.

Risk-Taking Customer

- **Preferences:** Increased exposure to wholesale volatility via real-time or similar rate structures and high cost demand charges; wholesale market pass-through demand charges may also be acceptable on energy supply contracts.
- **Concerns:** Operational awareness and control; decision over self-operated or third-party operated; current limited availability of optimal rate choices.

Source: Guidehouse

[21] Seventeen states plus Washington DC have deregulated markets with varying forms of retail choice. See additional information at: https://www.electricchoice.com/map-deregulated-energy-markets/

3.1.2 Rate Types

A utility tariff consists of many components; during the ratemaking process, a utility can select the à la carte options they require from a long menu, including the selection Table 3-2 shows. While the variety and complexity of rate structures continues to increase, many customers have had limited choice in how they pay for electricity service. Larger C&I consumers have generally been able to select from several rate structures, while the smaller customers have the most limited options. While a utility may have multiple residential customer rates, the options may be limited to customers with specific characteristics, such as those with electric heating, solar installations, or low-income qualification.

Ideally, customers have choices that enable them to manage risk in the way that best suits them. Progressive approaches to rate design (as described in Section 3.1.4) reduce the confusion of current rate design methods (see discussion in Section 3.1) and promote the use of transparent methods with appropriate rate levels to send the appropriate signals. As progressive rate design approaches gain traction and as the utility model of the 20th century continues to further evolve, rate choice is also expected to expand and evolve.

Table 3-2 maps many key rate types and their applicability to GEB strategies. For simplicity, the table describes the effect of each rate component type in isolation, which is generally not the case in practice. For example, customers charged for peak demand are usually also charged for energy consumption. The incentive levels in Table 3-2 are defined at the bottom of the table.

Table 3-2. Example Rate Structure Components and Alignment to GEB Strategies

Rate Structure Component	Efficiency	Load Shift	Load Shed	Generate	Modulate	Notes
Volumetric Charge	●	○	◔	◔	○	*Definition: Independent of timing (per kWh)* • Creates imprecise price signals; value limited to efficiency investments. • Commonly used for energy supply charges.
TOU Volumetric Charge	◕	◑	◑	◑	○	*Definition: Prices vary depending on time of day/week (per kWh)* • Incentivizes load shifting or shedding during peak hours.
Demand Charge	◔	◕	◑	◑	○	*Definition: Independent of timing (per kW)* • Incentivizes peak load reductions, load shifting or shedding, and onsite energy generation when feasible and beneficial for the customer, not necessarily the grid. • May apply separately to distribution utility charges and energy supply charges for large C&I customers in wholesale market regions.
Time-Differentiated Demand Charge	◑	●	◕	◕	○	*Definition: Prices vary depending on time of day/week (per kW)* • Incentivizes load shifting or shedding during peak hours.
Event-Based Pricing	○	●	●	●	○	*Definition: Prices change during critical grid peak periods (per kWh or per kW)* • Overlaps with retail DR in concept; includes CPP (a penalty) and critical peak rebate (a reward) pricing.
Dynamic Pricing	◕	●	◕	●	○	*Definition: Prices vary each hour reflecting wholesale variation (per kWh)* • Effective and flexible in communicating load shifting needs but does not always allow customers enough time to prepare (e.g., charging energy storage). Generally only suitable for advanced customers willing to bear risk.
Subscription Rates (Plus Enabling Tech)	◑	◕	◑	◑	○	*Definition: Prices fixed based on customer characteristics (per month)* • Provides predictable bills to customers while yielding some operational or technology decisions to the utility. • Coupling subscription rates with appropriate incentives for enabling technologies can create significant customer response benefits to the utility.
Legend	Increasing alignment of incentives between rate structure component and GEB strategy, ○ ◔ ◑ ◕ ●, where the empty circle represents no alignment and the full circle represents optimal alignment.					

Source: Guidehouse

While aggregators typically operate directly in wholesale markets or providing capacity to retail DR programs, some offer products to help manage certain components of customer rate structures. Aggregators can help manage wholesale market-based demand charges (as noted in Table 3-2), which may be a component of the energy supply rate structure for large customers. The aggregator leverages its market models to predict when regional or market-wide peak demand will occur and then notifies customers to curtail power. Such predictions are harder for individual customers to manage, so the aggregator-as-intermediary model provides actionable incentives driven by a less directly actionable wholesale market incentive mechanism.

3.1.3 Barriers and Opportunities

The US has over 3,700 utilities, each with multiple different rate structures that have been developed with different requirements. OpenEI's Utility Rate Database contains more than 57,000 different rates.[22] Residential rates typically provide little incentive for demand flexibility because most residential customers are billed solely on the total amount of energy (kWh) used during the billing period—often with no regard for peak load or load timing. Utilities often dictate that larger C&I customers pay volumetric charges (kWh) and demand charges (kW) to help contain costs for providing service; however, even for these customers, load timing is not always a consideration or is inconsistently addressed.

How utilities implement rate design varies widely, with multiple limitations on the effectiveness of the incentive mechanisms. Table 3-3 summarizes the limitations and the associated opportunities. Appendix A discusses basic rate design theory.

Table 3-3. Overview of Selected Barriers and Opportunities for Further Leveraging Demand Flexibility via Price-Based DR

Barrier		Opportunity
Muddled market signals: Lack of transparency and clarity in rate design that disconnects the incentive from the intended action and reduces the effectiveness of financial incentive mechanisms	→	Support for progressive rate design approaches (see Section 3.1.4) **Applies to:** Regulators and utilities
State regulations: Regulators in many states maintain utility business models that encourage load growth and infrastructure buildout to improve returns instead of maximizing demand-flexibility value.	→	Support for progressive utility business models at the state regulatory level based around resiliency, reliability, and decarbonization (e.g., decoupling sales volumes from financial returns) **Applies to:** Regulators and policymakers
Inconsistency: Customers with multiple locations must deal with inconsistency by operating buildings in different ways.	→	Development of standardized practices for modern rate design, enabling improved consistency between rate structures despite necessarily differing prices. **Applies to:** Regulators and utility industry associations

Source: Guidehouse

3.1.4 Modern Pricing Framework Opportunity

Progressive approaches to rate design are often referred to as alternative or modern pricing. The Public Utilities Fortnightly article, "A Modern Rate Architecture for California's Future" represents one view on the movement to more complex and advanced rate designs.[23] This guide provides a framework that outlines the following four key principles of modern rate design:

- **Transparency:** Bills need to separate out actual utility products from the costs to meet state-mandated policy programs so customers understand what they are paying for.

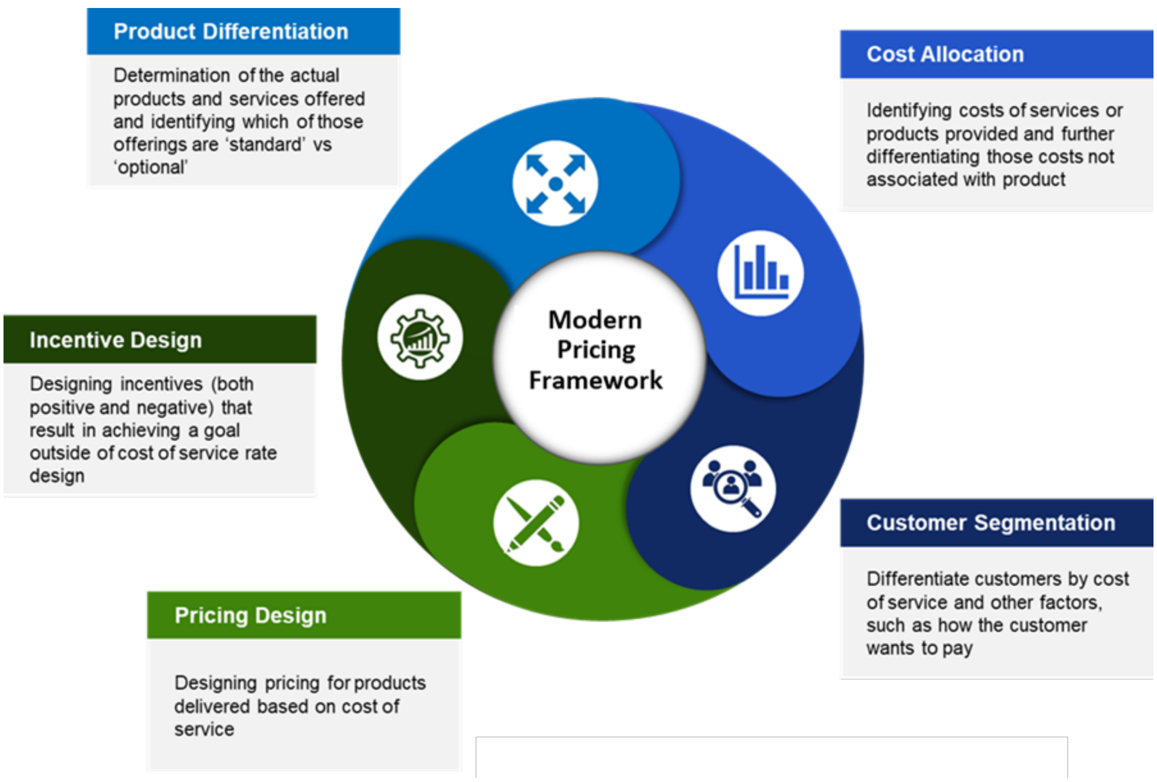
[22] OpenEI, "Utility Rate Database," accessed April 2021, available at: https://openei.org/wiki/Utility_Rate_Database

[23] Concepts borrowed from: "A Modern Rate Architecture for California's Future" by Margot Everett, Cynthia Fang, Andre Ramirez, and Jude Schneider, *Public Utilities Fortnightly*, November 1, 2018.

- **Equity:** Rates must be fair and minimize costs caused by one customer group being shifted to other groups, while recognizing that customers use the grid, consume products, and pay their bills in different ways.
- **Sustainability:** The new framework should be forward-looking and malleable so it can accommodate new products, services, and business models that achieve policy goals at a reasonable cost.
- **Access:** Customers should have equal access to the many options to manage their energy services.

To accomplish these four principles, progressive rate designs can rely on the Modern Pricing Framework, which consists of five key design features: product differentiation, cost allocation, customer segmentation, cost attribution, and incentive design. These features are linked and interdependent to facilitate a new pricing design structure. Progressive rate design generally follows the circular rate design process shown in Figure 3-3. Additional detail is provided in the following section.

Figure 3-3. Progressive Rate Design Elements: Modern Pricing Framework



Source: Adapted from "A Modern Rate Architecture for California's Future"[24]

[24] "A Modern Rate Architecture for California's Future", by Margot Everett, Cynthia Fang, Andre Ramirez, and Jude Schneider, *Public Utilities Fortnightly*, November 1, 2018.

3.1.5 Elements of Progressive Rate Design

This section further describes the five design features of the Modern Pricing Framework. These elements should be considered when designing rates that complement strategy to promote GEBs.

Product Differentiation

Product differentiation requires the industry to allow the actual products and services offered to be determined and to identify which of those offerings are standard and thus required versus those that can be options. Standard offerings can be offered by both the utility or a third party, but these require certain credentials and requirements uniform to all suppliers. Options can be competitive and market based. What options are offered, by whom, and at what price is at the discretion of the supplier and driven by the needs of the customer.

Cost Allocation

Cost allocation is the process of characterizing the cost of service for the products delineated during product differentiation. This process includes identifying the costs related to the product and those costs that are the direct result of policies (e.g., to fund critical initiatives, not associated with the product). The question of which customers should pay those costs is important to a robust and sustainable rate structure. Understanding costs at that level is also critical for regulators to achieve the goal of economic efficiency through market forces. By making sure the costs of each product or service to targeted customer groups are known, utilities cannot game the market by setting certain prices below costs.

Customer Segmentation

The utility industry has had the same customer classes for over 100 years: residential, commercial, industrial, and agricultural. This structure was based on the common customer load profile that resulted in an assessed cost of service that could be socialized across that group of customers. Those customer classes are becoming outdated as new DER technologies gain favor and classes lose their common load profile (e.g., an EV owner may consistently plug in their EV at home every evening, resulting in a different load profile than a general residential customer). Therefore, customers are now best suited to a more customized approach, and the industry is starting to accept that the traditional one-size-fits-all utility service is an antiquated and inefficient model.

Customer segmentation allows for different pricing options because the price of the services to the target customer can be based on how the customer wants to pay, not just on the products they use. This is critical for buildings with demand flexibility because they have different load profiles and different costs of service. Acknowledging the differences among customer groups is the starting point to better cost allocation and better attribution of value (return on investment) to those customers.

Pricing Design

Designing pricing options that send appropriate price signals and incentivize customers to modify behaviors leverages the first three steps of the Modern Pricing Framework. If products are well-defined, costs are well-known, and customers appropriately identified and segmented, pricing options can become highly effective in creating the desired outcomes for and by customers. Because costs are appropriately allocated to defined customer classes, there is more flexibility to explore pricing options without the risk of cost shifting among customer classes.

Incentive Design

Incentives can be positive, such as discounts or credits for change in behavior or adoption of new technologies, or incentives can be negative (i.e., punitive charges), such as premiums for added services or fees for costly customer behavior. Incentives are often used to remedy unintended cost allocation from implementation of policy.[25]

In many cases, rates muddle pricing and financial incentive design, resulting in incentives that are buried in the rate analytics and can potentially lead to unwanted consequences and opportunities for customers to game or abuse a rate design. By separating out the incentives associated with specific policy-related costs (e.g., driving toward carbon-reduction goals) and making them clearer and more actionable, customers can make better decisions and regulators can see the response to their policies. Furthermore, coupling incentive design with product differentiation and customer segmentation leads to options targeted to specific customers and product offerings, enabling competition for customer choices while ensuring affordable access to standard services.

3.2 Utility-Operated Programs (Retail DR)

3.2.1 Overview

Utilities may opt to create DR programs to access demand flexibility benefits from buildings for distribution-level purposes or for transmission-level purposes in the case of a vertically integrated utility. This is true for any utility regardless of the presence of a wholesale market or not; however, those integrated utilities that serve as their own balancing authorities may have additional incentive due to other obligations to provide load balancing and power quality across all timescales by offering reserves and ancillary services. The structure of their DR programs is driven by their specific goals and objectives, which are determined from their unique circumstances (see Section 2.1 for review of objectives in the context of the demand-flexibility value proposition).

Utilities face many challenges in implementing effective programs, but DR programs are not a new concept, having been in place for more than 20 years in some places. SEPA's *2019 Utility Demand Response Snapshot* found 20.8 GW of enrolled DR capacity across 190 surveyed utilities.[26] Best practices are now well established but still evolving for structuring and implementing IT and operational technology (OT) systems, conducting evaluation, measurement and verification (EM&V), dispatching customers, marketing, customer education, self-implementation versus third-party implementation (by a DR aggregator), and more. Utility DR programs are not ubiquitous, as regulatory frameworks do not universally motivate the use

[25] Utilities are often tasked with implementing policy through rate design, restricting the utility's options and often creating numerous opportunities for third-party entrants to arbitrage. This creates inefficiency and provides discounts to customers who can afford the time, energy, and financial resources (including credit) to participate in these options, leaving remaining customers, who often cannot afford to, pick up the additional costs.

[26] SEPA, *2019 Utility Demand Response Market Snapshot*, September 2019, accessed December 2020 via: https://sepapower.org/resource/2019-utility-demand-response-market-snapshot/. (see Executive Summary on p. 7).

of DR. For additional data on the current enrolled DR capacity in the US, including breakdowns by customer segment and program types, refer to the previously referenced *2019 Utility Demand Response Market Snapshot* from SEPA.

Figure 3-4 provides an overview of program structure considerations for customers with different risk profiles. Utilities should consider the differences in customer risk preferences in their program designs (see Section 2.3.5 for discussion of customer risk profiles related to energy spend and operations).

Figure 3-4. Program Structure Considerations by Customer Energy Spend Profile

Risk-Averse Customer

- **Preferences:** Conservative (low kW) nominations to minimize disruption to operations; third-party control or dispatch ideal (otherwise enrollment in infrequent and likely emergency-only programs).
- **Concerns:** Unexpected performance penalties' impact on predictable cash flows.

Risk-Taking Customer

- **Preferences:** Aggressive (higher kW) nominations, greater willingness to curtail operations (e.g., production) and greater openness to multiple, frequent dispatch programs.
- **Concerns:** Access to lucrative programs that fully value demand flexibility.

Cross-cutting considerations:

- High frequency dispatches can lead to fatigue, requiring extra planning and/or advanced technology.
- Availability highly inconsistent across the US; progressive utilities provide greater options.

Source: Guidehouse

3.2.2 Utility Program Structure Types

Utility programs are designed specifically around an individual utility's needs and goals, resulting in a variety of program structures. These programs can be defined by how they address the four characteristics listed in Figure 3-5. Each characteristic may be applied in different ways, such that they are not mutually exclusive with the same utility program.

Figure 3-5. Utility Program (Retail DR) Characteristics Overview

Control

- **Direct load control:** Curtailment of opt-in customer load is initiated by the utility or aggregator via automation (e.g., smart thermostat); may be called "asset-based" when controlling a battery or generator
- **Customer-Initiated:** Curtailment is initiated by the opt-in customers at a time specified in a text or mobile-app notification from the utility or aggregator; may be called "behavior-based"

Incentive

- **Reward (Carrot):** Customers may opt out of a customer-initiated dispatch if they deem the incentive to be insufficient (may be applied with or without a penalty)
- **Penalty (Stick):** Penalties may be instituted due to underperformance or failure to perform in a customer-initiated dispatch (commonly applied alongside a rewards)

Segment

- **Residential:** Historically focusing on HVAC (AC switch or smart thermostat integration) and water heating equipment
- **C&I:** Wide array of end use equipment may be curtailed, with more advanced integration with building automation systems

Credit

- **Participation credit:** Fixed credit or payment for participating when utility has direct load control (e.g., A/C switch or smart thermostat); reduced need for high-accuracy EM&V
- **Performance credit:** Variable credit or payment based on performance during the actual event, requiring advanced metering infrastructure and associated EM&V (may also receive participation credit)

Source: Guidehouse

Behavioral DR is a unique type of program that cuts across many of the common characteristics of other programs. While each utility designs their behavioral program differently, a typical program is opt out (contrary to all other retail DR programs) for all customers within a specific region (e.g., one or more heavily-strained substations). Additionally, most behavioral programs provide no performance incentive aside from saving money within the bounds of their existing utility rate structure. The dispatch is based solely around a utility request for customers to voluntarily curtail usage for a specific day and time. To motivate participation, a utility may provide data visualization communications to help customers understand the value they provide to the grid and their comparative performance relative to other customers (i.e., gamification); in some cases, they may provide gift cards.

Table 3-4 maps selected utility program types and their applicability to GEB strategies.[27]

[27] Efficiency-specific programs, where demand flexibility is not the focus, are common but are out of scope for this report as they are not primarily designed to provide value in the context of the three DR options shown in Figure 1-1.

Table 3-4. Example Utility Program Types and Alignment to GEB Strategies

Utility Program Types	Efficiency	Load Shift	Load Shed	Generate	Modulate	Notes
Performance-Based	○	●	●	◔	○	*Definition: Payment/credit based on measured performance* • Includes programs with customer/aggregator-initiated curtailment, with compensation improving as customer modifies behavior and optimally operates their equipment.
Participation-Based	○	●	◕	◑	◑	*Definition: Payment/credit based on participation regardless of performance* • Includes direct load control programs (e.g., AC switch, controlled by utility) where eligibility requirements ensure performance, with compensation preset based on expected performance. • Modulation is primarily from generation and storage, but research suggests viability via large-scale coordinated load control.[28]
Voluntary Behavioral	○	◔	◔	○	○	*Definition: Voluntary communication-based programs, generally with no financial incentive* • Sole focus is load shedding or shifting during emergency events.
Legend	Increasing alignment of incentives between rate structure component and GEB strategy, ○ ◔ ◑ ◕ ●, where the empty circle represents no alignment and the full circle represents optimal alignment.					

Source: Guidehouse

3.2.3 Barriers and Opportunities

With 50 states each having their own regulators and more than 3,700 utilities, utility program structures are governed by inconsistent rules and political drivers. The result is limited standardization and a resulting slow growth in the size of the market for utility program-based DR. Table 3-5 summarizes the limitations and the associated opportunities for program structures.

Table 3-5. Overview of Selected Barriers and Opportunities for Further Leveraging Demand Flexibility via Retail DR

Barrier		Opportunity
State policies: Regulators in many states maintain utility business models that emphasize load growth and infrastructure buildout to improve returns instead of maximizing demand-flexibility value.	↔	Support progressive utility business models with state regulators, with focus on resiliency, reliability, decarbonization (e.g., decoupling sales volumes from returns). **Applies to:** Regulators and policymakers
Inconsistent designs: Aggregators and building owners that have multiple locations face substantive burden in entering new programs due to inconsistency. Customers also then face operations inconsistency between buildings.	↔	Support development of industry standards or best practices for DR program design and implementation, improving consistency between utilities. **Applies to:** Utilities and utility industry organizations

[28] ORNL evaluated the potential to use a network of HVAC equipment items for frequency regulation; details available at: https://www.ornl.gov/publication/coordination-and-control-building-hvac-systems-provide-frequency-regulation-electric-0

Barrier		Opportunity
Implementation complexity/burden: Outdated IT systems and unnecessarily complex participation processes (e.g., modeling requirements) introduce administration burden (time and cost) that hinders participation, especially burdening small resources and aggregators.	↔	Support modernization and simplification of IT systems and processes for participation, including enrollment, data sharing (e.g., green button), and measurement and verification. **Applies to:** Utilities and regulators
Decentralized regulation: With primary regulatory oversight of utilities residing at the state level, expansion of DR relies on initiatives at the state or utility level, resulting in slow growth of DR programs.	↔	Support development of industry standards or best practices for coordinated and consistent policy and regulatory treatment. **Applies to:** Regulators and utility industry organizations

Source: Guidehouse

3.3 RTO/ISO-Operated Wholesale Markets (Wholesale DR)

3.3.1 Overview

Wholesale electricity markets provide opportunities for building owners to monetize investments in demand flexibility through opt-in participation in markets. SEPA, in its *2019 Utility Demand Response Market Snapshot* report, found that ISOs and RTOs in the US had more than 23 GW of DR capacity enrolled (all customer segments).[29] Depending on a customer's capabilities, they may participate by providing one or more different services. Each wholesale electricity market has its own service (i.e., product) definitions, including requirements for availability, baseline definitions, penalties for underperformance, and differing expectations for frequency and duration of dispatch.

In September 2020, FERC passed Order 2222, which seeks to expand DERs' equitable participation in wholesale markets. FERC describes Order 2222 as follows:

> *This rule enables DERs to participate alongside traditional resources in the regional organized wholesale markets through aggregations, opening U.S. organized wholesale markets to new sources of energy and grid services. It will help provide a variety of benefits including lower costs for consumers through enhanced competition, more grid flexibility and resilience, and more innovation within the electric power industry.*[30]

FERC 2222 did not eliminate the provision from FERC Orders 719 and 719a in 2008 that allowed states to opt-out of DR participation in wholesale markets, which has prevented any participation of buildings with demand flexibility in wholesale markets in eighteen states ever since (mostly in the Midwest independent System Operator and Southwest Power Pool

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[29] SEPA, *2019 Utility Demand Response Market Snapshot*, September 2019, accessed via: https://sepapower.org/resource/2019-utility-demand-response-market-snapshot/. Figure 16 in the report provides the following footnote: "These numbers are based on publicly available data from the ISOs and RTOs and communication with ISO and RTO members. For PJM, NYISO, and ISO New England, the numbers shown are capacity market obligations. For MISO, ERCOT, and CAISO, they are a combination of the enrollment in the different DR programs that each RTO offers."

[30] FERC Order No. 2222: Fact Sheet; accessed November 24, 2020 at: https://www.ferc.gov/media/ferc-order-no-2222-fact-sheet

markets). In March 2021, FERC issued Order 2222-A and a Notice of Inquiry that provide substantive change to the opt out and could ultimately lead to its elimination.[31]

These regulatory changes at FERC provide an example of the evolving views on financial incentive mechanisms and access to markets by a broad range of DERs, including buildings with demand flexibility. Many view Order 2222 as a game changer for smaller, behind-the-meter DERs that can usher in a new era of DR that maximizes the value that buildings can contribute to grid balancing.

Under the Order, ISOs and RTOs must submit plans for how they intend to proceed. The resulting market changes we are likely to see in the next 3-5 years will expand opportunities for building owners to monetize their investments in demand-flexible capabilities; however, the changes will be limited to only those regions with wholesale electricity markets.

Current rules typically require active engagement by each customer's distribution utility during registration for data or other needs. As a result, utilities are gatekeepers for customer participation in market structures. Current incentive structures do not align utility and wholesale market goals because utilities receive little or no benefit from their customers' participation in wholesale DR. Their participation instead serves as additional administrative burden and perpetuates misalignment of goals.

Figure 3-6 provides an overview of market structure considerations for each customer profile. Market operators should consider the differences in customer risk preferences in their program designs and aggregators should do the same in their go-to-market strategy (see Section 2.3.5 for discussion of customer risk profiles related to energy spend and operations).

Figure 3-6. Market Structure Considerations by Customer Energy Spend Profile

Risk-Averse Customer	**Risk-Taking Customer**
• **Preferences:** Conservative (low kW) nominations to minimize disruption to operations; third-party control or dispatch enrollment in predictable or infrequent and likely emergency-only programs (e.g., capacity markets) preferred. • **Concerns:** Unexpected performance penalties' impact on predictable cash flows.	• **Preferences:** Aggressive (higher kW) nominations in markets, greater willingness to curtail operations (e.g., production) to provide market service and greater openness to multiple, frequent dispatch services. • **Concerns:** Market access/participation limitations geographically, including lack of wholesale markets everywhere and regional limitations (e.g., states that opt-out).

Source: Guidehouse

[31] In Order 2222-A, FERC is "setting aside its finding in Order No. 2222 that demand response resource participation in heterogeneous distributed energy resource aggregations are subject to the opt-out." See discussion in "FERC to Allow Distributed Energy Resource Aggregations in Wholesale Electric Markets to Include Demand Response Resources," JDSUPRA, March 25, 2021, available: https://www.jdsupra.com/legalnews/ferc-to-allow-distributed-energy-9782462/ FERC's notice of Inquiry is available at: FERC Notice of Inquiry, March 25, 2021, available: https://www.federalregister.gov/documents/2021/03/25/2021-06106/participation-of-aggregators-of-retail-demand-response-customers-in-markets-operated-by-regional#citation-2-p15939 with additional discussion at: https://www.ferc.gov/news-events/news/ferc-addresses-demand-response-opt-out-certain-der-aggregations.

3.3.2 Market Structure Types

For those buildings located in a wholesale market area, the level of demand flexibility at the site and the extent to which control is automated dictate the ability of the customer to enroll in wholesale DR. The greater the flexibility and the greater the automation, the greater the potential for market participation and financial return on the investments. For example, a building with highly flexible demand served by a utility in the PJM Interconnection (an RTO) territory could conceivably use multiple assets to participate in the PJM capacity market for its emergency or pre-emergency Load Management DR program (that receives real-time energy market payments when dispatched) and frequency regulation and synchronized reserves (both part of ancillary services market). The characteristics of the demand-flexible assets and their controls determine what services each one can provide.

The three primary wholesale market structures can be characterized as follows:

- **Capacity or emergency services:** Capacity (kW) markets to assure future resource adequacy, typically for use in emergency situations (e.g., summer heat wave) where additional capacity is required for a relatively small number of hours per year to ensure sufficient capacity to serve the load.
- **Ancillary services:** Reserve markets, frequency regulation, and ramping services, which each serves different objectives to help manage supply and demand over different timeframes and has its own rules and requirements.
- **Energy markets:** Real-time and day-ahead markets for energy (no capacity payments); best suited for advanced customers having advanced dispatchable assets with excess capacity who are seeking increased merchant generation revenue.

In some markets, it is possible for customers to participate directly, but this is uncommon (see Figure 1-3), as most participate via an aggregator. Typically, only the most advanced, large customers (typically industrial customers) consider direct participation. An aggregator's value proposition for a demand-flexible customer is streamlined, low-hassle participation. Aggregators sign contracts with customers and act as an intermediary between the grid operator and the customers in exchange for a fee. This fee is sometimes a percentage of the market revenue.

By partnering with an aggregator, the building owner does not need to navigate the complex rules, regulations, approvals, and paperwork that may be required for participation. The aggregator takes a cut of the revenue in exchange for easy access to the market and often provides access to meter data, analytics, and advanced integrations with the building management system.

Table 3-6 maps a selection of market service types and their applicability to GEB strategies. Market services are all customer-initiated (no direct load control from the grid operator), but the signal from the grid operator can be automated as appropriate, which is increasingly critical as the response times decrease. Frequency response services require signal matching within just a few seconds or less.

Table 3-6. Example Market Service Types and Alignment to GEB Strategies

Market Service Types	Efficiency	Load Shift	Load Shed	Generate	Modulate	Notes
Capacity Market	●	●	●	◑	○	*Definition: Load reduction tools for securing future capacity to ensure resource adequacy (often emergency DR)* • Acceptability of generation assets depends on local emissions regulations that can be challenging for some backup fossil generators.
Ancillary Services	○	●	●	●	○	*Definition: Reserves for balancing supply and demand* • Includes ramping, spinning reserves, non-spinning reserves, and other ancillary services with response times of minutes to hours.
Ancillary Services (Ultra-Fast Response)	○	○	○	◑	●	*Definition: Ultra-fast response for maintaining grid frequency* • Frequency regulation, primarily from generation and storage, but research suggests viability via large-scale coordinated load control.[32]
Energy Market	○	◑	◑	●	○	*Definition: Wholesale merchant energy, or economic DR* • Includes real-time and day-ahead markets; curtailment may interrupt operations so it is less appealing than other services for building owners.
Legend	Increasing alignment of incentives between rate structure component and GEB strategy, ○ ◔ ◑ ◕ ●, where the empty circle represents no alignment and the full circle represents optimal alignment.					

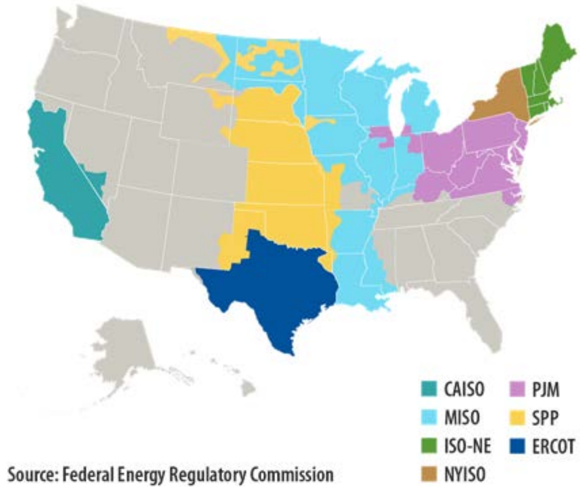
Source: Guidehouse

3.3.3 Barriers and Opportunities

Wholesale markets are not available to all customers in the US. As Figure 3-7 shows, many regions, including the Southeast, the Pacific Northwest, and the Rocky Mountain states do not have wholesale electricity markets. Instead, power is provided by vertically integrated utilities with their own balancing authorities that ensure grid reliability. This inconsistency is due to the state and regional regulations and agreements that are in place in lieu of regulatory mandates at the federal level.

[32] ORNL evaluated the potential to use a network of HVAC equipment items for frequency regulation; details available at: https://www.ornl.gov/publication/coordination-and-control-building-hvac-systems-provide-frequency-regulation-electric-0

Figure 3-7. Map of Wholesale Electricity Markets in the Continental US



Source: EPA[33]

Table 3-7 summarizes the limitations and the associated opportunities for market structures.

Table 3-7. Overview of Selected Barriers and Opportunities for Further Leveraging Demand Flexibility via Wholesale DR

Barrier		Opportunity
Limited availability: Lack of wholesale markets across large swaths of the US.	↔	Support federal regulatory change to expand reach of wholesale markets across entire US. **Applies to:** Regulators and policymakers
Inconsistent DER treatment (including building load).	↔	Unified market treatment (as sought by FERC Order 2222) and market/service standardization **Applies to:** Regulators and policymakers
Implementation complexity/burden: Outdated IT systems and unnecessarily complex participation processes (e.g., modeling requirements) introduce administration burden (time/cost) that hinder participation, especially for small resources and aggregators.	↔	Support modernization and simplification of IT systems and processes for participation, including enrollment, data sharing (e.g., green button), and measurement and verification. **Applies to:** Market operators, regulators, and policymakers
State opt outs: FERC, via Order 719 and 719a from 2008, allows states to opt out of third-party aggregator DR for wholesale markets (see discussion of progress in Section 3.3.1).	↔	Support regulatory change to eliminate opt-outs and improve participation consistency across markets/states/regions. **Applies to:** Regulators and policymakers
Utility inertia: Lack of utility incentive to support or facilitate wholesale DR limits collaboration; utility involvement is typically required during registration.	↔	Support regulatory alignment of incentives to improve stakeholder collaboration and streamline participation **Applies to:** Regulators and policymakers
Inconsistent market structures: Includes penalties, measurement and verification, performance definitions, etc.	↔	Support standardization of market design or unification of markets. **Applies to:** Regulators and policymakers

Source: Guidehouse

[33] Map available from EPA at: https://www.epa.gov/greenpower/us-electricity-grid-markets.

4. Linking Demand Flexibility to Incentive Mechanisms

The sections above outlined stakeholder goals and the design elements of rates and financial incentive mechanisms. Linking these two dimensions is critical to the identification of the utility rate and DR programs that will optimize the benefits of demand flexibility in buildings. Table 4-1 synthesizes the stakeholder goals from Section 2 (see details on each stakeholder in Section 2.3) with the characteristics of the financial incentive mechanisms from Section 3.

Table 4-1 reflects the goals for various stakeholders, using the following summary context:

- **Reliability:** Protection from grid outages
- **High power quality:** Maintaining appropriate voltage or frequency at varying grid scales (e.g., individual feeder, substation, or even broader)
- **Resource adequacy:** Sufficient capacity to ensure power availability for peak periods
- **Cost-reflectiveness:** Alignment with actual costs incurred to provide utility service
- **Predictability:** Consistency and ability to anticipate bill savings
- **Bill/cost savings:** Customer ability to reduce utility bill costs (or generate additional payments (e.g., wholesale DR) OR utility ability to reduce cost of service
- **Maximize revenue:** Utility opportunity to generate revenue
- **Occupant satisfaction:** Comfort and productivity of people in the building
- **Payment structure satisfaction:** Comfort with the way in which billing/payments occur, including ability to intuitively understand if cost is reflective of use

The resulting alignment scores for each rate, program, or market structure type (see Table 4-1) indicate the extent to which the structure aligns with goals of the various stakeholders, with the highest scores coming from utility programs and market programs. To maintain simplicity, the alignment score is a sum of the filled portions of the Harvey Balls, such that the score indicates the greatest alignment with the most stakeholder goals.

Table 4-1. Alignment of Incentive Mechanism Types to Stakeholder Goals

↑ Stakeholders / *Goal* → / *Incentive Mechanism* ↓	Reliability	High Power Quality	Resource Adequacy	Cost Reflective	Predictability	Bill/Cost Savings	Maximize Revenue	Occupant Satisfaction	Payment Structure Satisfaction	**Alignment Score**	**Drivers/Notes**
Regulator	X			X							
Grid Operator	X	X	X								
Utility	X			X		X	X				
Aggregator					X	X*					
Customer					X	X		X	X		
Contractor					X		X**	X			
Utility Rate Structure Type											
Volumetric Charge	○	○	○	○	◑	○	◑	●	◕	**2.75**	*Definition: Independent of timing (per kWh)* • Simplest rate, incentivizes efficiency
Demand Charge	○	○	◑	◑	◔	◑	◔	◕	◑	**3.25**	*Definition: Independent of timing (per kW)* • Incentivizes peak load management
TOU Volumetric Charge	○	○	◑	◑	◑	●	◑	◑	◑	**4**	*Definition: Prices vary by time of day/week/season (per kWh)* • Incentivizes volumetric reductions
Time-Differentiated Demand Charge	○	○	◕	◕	◑	●	◔	◑	◔	**4**	*Definition: Prices vary by time of day/week/season (per kW)* • Incentivizes load management in alignment with grid peaks
Event-Based Pricing	◑	○	●	●	◔	●	○	◔	◔	**4.25**	*Definition: Prices change during critical grid peaks (per kWh)* • Strong incentive for market-aligned peak load management
Dynamic Pricing	◑	○	●	●	◔	●	◑	◔	◔	**4.75**	*Definition: Prices vary by market or system status (per kWh)* • Strong incentive for market-aligned peak load management
Subscription Rates	○	○	○	◕	●	◑	◔	●	●	**4.5**	*Definition: Prices fixed by customer features (per month)* • Depends on assumptions about operations
Utility Program Structure Type											
Performance-Based	●	◔	◑	◑	◑	●	●	◔	◑	**5.5**	*Definition: Payment/credit based on measured performance* • Support reliability and resource adequacy; kWh or kW
Participation-Based	●	○	◑	◑	●	●	◑	◑	●	**6**	*Definition: Payment/credit based on participation* • Simple, automated performance; binary performance
Voluntary Behavioral	◕	○	◑	◔	◑	◔	◑	◑	●	**4.25**	*Definition: Voluntary communication-based programs* • Incentivizes uncompensated emergency curtailment
Market Structure Type											
Capacity Market	●	○	●	●	●	●	○	◑	●	**6.5**	*Definition: Assures capacity to ensure resource adequacy* • Energy payments may also apply (small share of revenues)
Ancillary Services	●	◕	◑	●	◑	●	○	◑	◑	**5.75**	*Definition: Reserves for balancing supply and demand* • Supports reliability and lowest-cost resource adequacy
Ancillary Services (Ultra-Fast Response)	●	●	○	●	○	●	○	◔	◑	**4.75**	*Definition: Ultra-fast response for maintaining grid frequency* • Supports reliability and power quality
Energy Market	◑	○	●	●	○	●	○	◑	◑	**4.5**	*Definition: Providing wholesale merchant energy* • Supports lowest-cost resource adequacy

Legend: *Increasing alignment of incentive mechanism and goal, ○ ◔ ◑ ◕ ●, where the empty circle represents no alignment and the full circle represents optimal alignment and Alignment Score is the sum of filled portion of each Harvey Ball in the row.*

Notes: *May be more appropriately labeled "maximize revenue" for aggregators but aligns best in this table with bill savings (applies only to utility program and market structures).

**Third-party contractor revenue applies only where advanced technologies or operating contracts are required or used (not explicitly shown).

Source: Guidehouse

The alignment score by itself is not necessarily an indicator of which structure is optimal to pursue as other considerations can limit the potential value. For example:[34]

- **TOU price ratios:** TOU drives impact on peak demand that is proportional to the off-peak price to peak price ratio, so if pricing is not set appropriately, value is limited.
- **Lack of awareness/interest:** Dynamic pricing is the highest scoring utility rate structure type, but some customers may respond poorly for multiple reasons, including lack of awareness, lack of demand management technical or operational capabilities, or simply lack of prioritization or interest in closely managing energy spend. In this case, the ideal economic model does not account for customers' economically irrational behavior.
- **Lack of flexibility:** Customer segments having low electricity consumption flexibility, including low- and moderate-income customers, can be negatively impacted by any structure that does not also provide additional resources to enable demand flexibility. This highlights the value of increased choice between different rate structures to suit individual customer needs.

5. Conclusions

5.1 Summary of Incentive Mechanisms

This guide has characterized three different financial incentive mechanisms, rate structures, utility program structures, and market structures, that each motivate behavior by building owners and operators to provide demand flexibility in different ways:

- **Price-based DR (utility rates)** motivates customers to reduce volumetric consumption or peak demand during fixed periods (peak vs. off peak) or through events (e.g., critical peaks). Optimized energy consumption around the specific rate design can reduce electric bills. Increasingly, different tariffs and rate designs are available for C&I customers depending on their risk appetite.
- **Utility-operated programs (retail DR)** motivate customers to reduce peak demand during specific event periods, which earn customers bill credits or payments based on their performance for customer or aggregator-initiated dispatches, or simply through participation for utility-initiated automated dispatches.
- **RTO/ISO-operated wholesale markets (wholesale DR)** motivate reductions in demand during specific event periods, much like some retail DR, in exchange for revenue based on performance and market rules. For customers with advanced controls, multiple markets may be available to address different objectives (e.g., emergency capacity vs. reserves). Most wholesale DR for buildings is accessed via aggregators.

These mechanisms are the economic signals that utilities and regulators can use to motivate behaviors. Use of these mechanisms vary across the US depending on the utility, the state policies and goals, regulations, and existence of wholesale markets. As a result, use of these mechanisms to leverage building demand flexibility varies dramatically. For customers living in states with deregulated utilities, competitive energy supply, and wholesale markets

[34] See additional discussion of TOU and dynamic pricing at "Beyond TOY: Is more dynamic pricing the future of rate design?" *Utility Dive,* July 17, 2017, available: https://www.utilitydive.com/news/beyond-tou-is-more-dynamic-pricing-the-future-of-rate-design/447171/

(RTOs/ISOs), multiple mechanisms may be in play simultaneously. Other customers may be limited to their utility-mandated rate structure, which in some cases, is structured with few or no mechanisms to maximize the value of demand flexibility.

Momentum is growing for utilities to think differently about their rate design approaches, including use of modern pricing frameworks and offering multiple rate options for customers with different risk appetites. FERC 2222 and 2222-A create additional momentum to improve the treatment of buildings as DERs, but this is limited to those parts of the country with wholesale markets. Substantial gaps still exist for the use of all three financial incentive mechanisms to maximize use of buildings as grid resources. As the penetration of intermittent renewables continues to grow to meet climate goals, maximizing demand flexibility in buildings will only become more critical.

5.2 Next Steps

The assessment of opportunities and limitations in Section 3 provides clarity on the next steps that can further drive improved incentive transparency and clarity, predictability, and monetizability for customers with demand flexibility. Table 5-1 summarizes the identified opportunities to expand demand flexibility in buildings as a critical demand-side resource. They are a critical and cost-effective component of load balancing and will become increasingly important as penetration of intermittent renewables increases.

Table 5-1. Summary of Opportunities for Expanding Demand Flexibility in Buildings via All Three Key DR Options

Financial Incentive Mechanism	Opportunity
Cross-Cutting	1. **All Financial Incentive Mechanisms:** Improved consistency and standardization (see opportunities 5, 6, 7, 8, 9, 10 in this table)
	2. **Rates/Markets:** Progressive state regulations and utility business models focusing on resiliency, reliability, and decarbonization
	3. **Programs/Markets:** Modernization of IT and processes: enrollment, data sharing (e.g., green button), and M&V to reduce administrative burden
Rate Structures	4. Alternative/modern rate design
	5. Increased consistency in rate design approaches and structures between utilities (despite necessarily differing prices)
Utility Program Structures	6. Increased consistency in DR program design and implementation between utilities
	7. Increased consistency of regulatory and policy treatment
Market Structures	8. Federal regulatory change to expand reach of wholesale markets across the entire US
	9. Unified markets and treatment of DER (as sought by FERC Orders 2222/2222-A); market/service standardization
	10. Elimination of state opt outs and consistent participation enabled across markets/states/regions
	11. Regulatory alignment of incentives with utilities to streamline participation

Source: Guidehouse

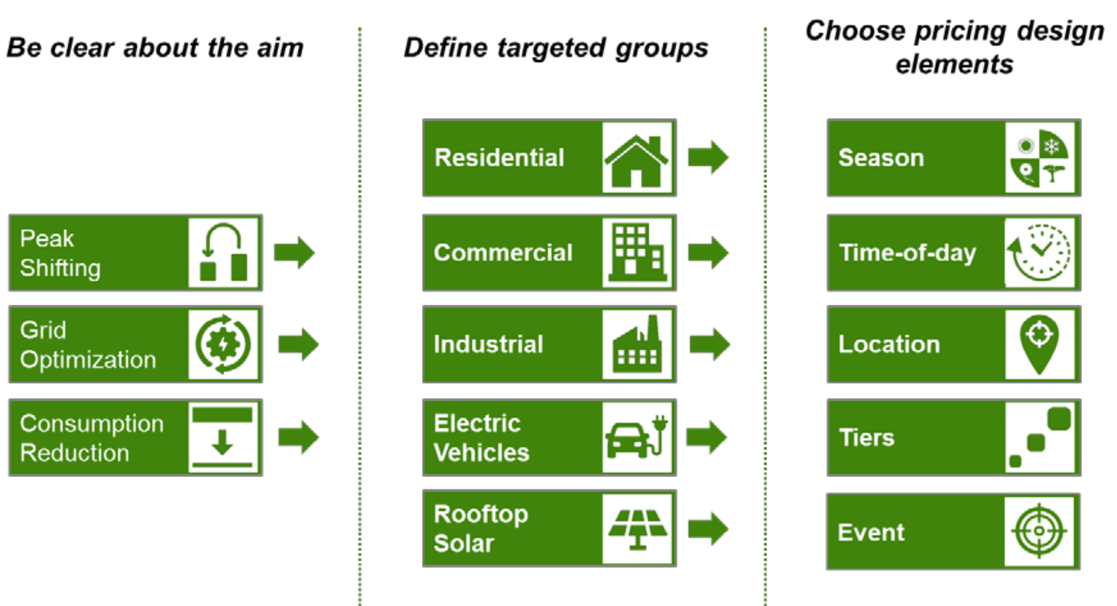
Appendix A. Basic Rate Design Theory

There are certain fundamentals of utility rate design that are well established and foundational. These principles were first fully articulated in *Principles of Public Utility Rates* by James Bonbright, published in 1961. The principles outlined in this book, now often referred to as The Bonbright Principles can be summed up as rates should:

- Reflect costs and create economic efficiency by avoiding subsidies and promoting innovation
- Be equitable, fair, and non-discriminatory
- Result in full recovery and revenue stability for utilities
- Create bill stability for customers
- Be simple and easily understood by customers

The rate design process is highly data-driven and balances many issues and considerations. Data is used to determine when the peak rate periods will occur, what are the optimal durations for those periods, and other facets. However, while data drives the design of rates, rate design is ultimately optimized with the customers in mind and will only succeed when customers are able to understand and respond to the rate. Figure A-1 summarizes the rate design approach.

Figure A-1. Approach to Rate Design

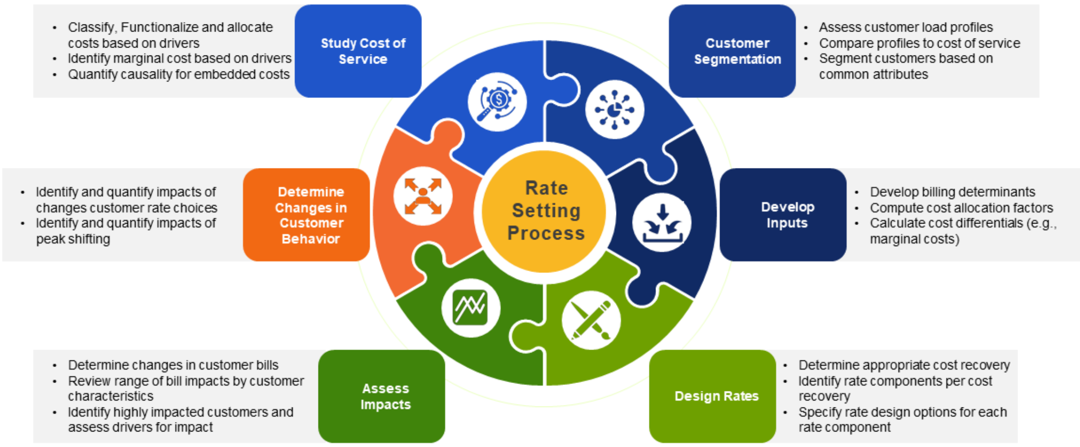


Source: Guidehouse

Objectives of rates vary depending upon the stakeholders, creating a balance between data driven analytics and policy driven desired outcomes. A fundamental part of rate design is understating the targeted groups. Customers have differing levels of ability to respond to rate structures. To that end, the rate designer often considers the needs and capabilities of customers and therefore adopting pricing elements that best suite those customer needs.

Pricing design elements are driven by customer demands and utility costs. Figure A-2 shows the typical rate setting process.

Figure A-2. Rate Setting Process



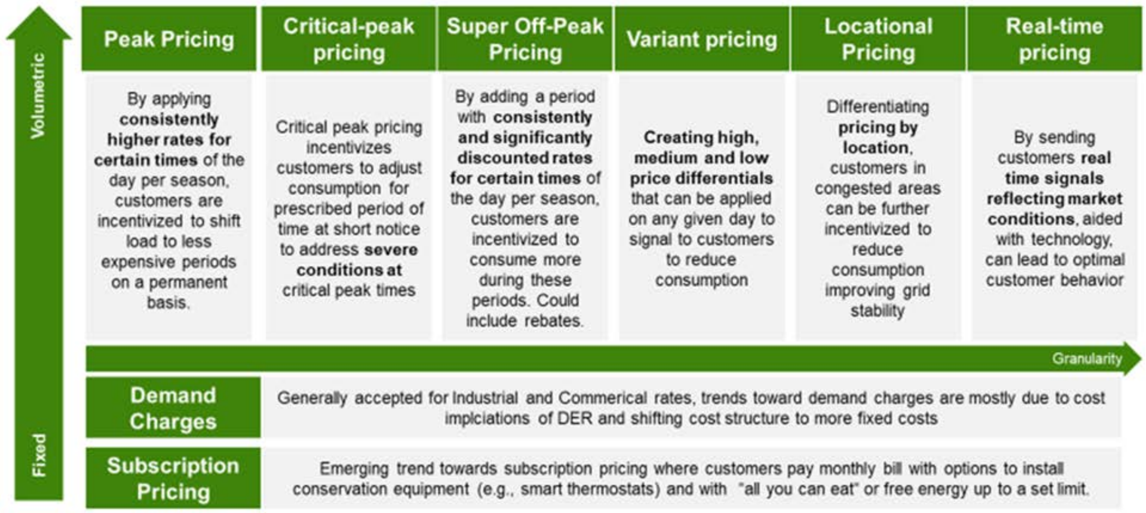
Source: Guidehouse

Utilities typically start the rate design process by performing cost of service studies that generally follow a standardized approach where costs are separated by the function for which the costs were incurred (Functionalization), the driver of the costs (Classification) and who should pay for those costs (allocation). The general goal of these studies is to create a relationship between costs and what drives that cost.

Once costs and drivers of those costs are determined, costs and cost drivers are used to segment customers. Specifically, customers with similar cost of service characteristics, and, in some cases, sophistication and ability to understand and respond to price signals. After customer groups are determined, costs are then allocated to a customer group based on that group's contribution to the drivers of that cost (e.g., demand related costs are allocated to the customer class based on their contribution to demand). Upon allocation of costs, rates can then be designed.

Rates are usually made of up several components, or Rate Components, to recover individual costs based on the driver. Rate components can reflect a cost type (e.g., costs related to generating a kWh) and the unit of measure for the rate (e.g., volumetric rates are per kWh while fixed rates are per customer month). The types of pricing options vary in complexing by the number of units of measure in the rate structure and if there is an element of time differentiation in the rate. For example, a rate may have a fixed charge to recover customer related costs and a volumetric, or kWh, charge to recover costs that changes based on when the customer consumes the kWh when energy levels change. Figure A-3 shows the range of rate options typically available to utilities.

Figure A-3. Overview of Rate Design Options



Source: Guidehouse

Table A-1 shows a comprehensive list of rate options.

Table A-1. Pricing Options

Pricing or Program Structure	Description
Flat Volumetric Charge	• Constant price per kWh of customer's use.
Demand Charge	• Constant price per kW of customer's demand.
TOU Volumetric Charge	• Volumetric price per kWh that varies by season and time of day.
Time-Differentiated Demand Charge	• Demand charge per kW of customer demand that varies by season and time of day.
CPP	• Event based pricing that is called upon a fixed number of times in a designated period and overrides the customer's normal pricing.
Critical Peak Rebate	• Event based rebated that provides customers a bill credit if the customer materially modifies their consumption during the event.
Real-Time Pricing	• Pricing that changes a day ahead, or even hour ahead, reflecting current market conditions.
Subscription Rates	• Flat rate for certain level of service, such as demand or connected load, and is accompanied by incentives for the customer to install technologies. Potentially can have volumetric rates to create price signals for consumption.
Interruptible Rates	• Customers get discounted rate in return for being interrupted by the utility at critical peak periods.
Two-Way Flow Rates	• Rates that account for electricity that flows back and forth from the customer, for example from solar PV, battery, or EVs
Targeted Class Rates	• Rates designed for a specific rate class, such as large C&I customers or Commercial Electric Vehicles and, potentially, GEBs.
Power Factor Charges	• Charges for customers exceeding power factor levels

Pricing or Program Structure	Description
Inclining Block	• Constant prices up to a certain level of consumption or block of power, with pricing increasing as customer use increases.
Declining Block	• Constant prices up to a certain level of consumption or block of power, with pricing decreasing as customer use increases.
DR	• Customer is provided incentive payment in return for commitment to curtail load to certain levels upon request by the utility
Standby Rate	• Standby rates are designed for accounts with generators that interconnect to and operate in parallel with a utility's electric system. The rate provides backup electric service when the generator(s) is partially or completely shut down.
Green Rates	• Rates that provide customers with access to electricity generated in-part or fully from renewables
Utility Direct Control	• Customer is provided an incentive or a pricing discount for allowing the utility to control certain behind the meter technologies. These controls can either interrupt load or modify dispatch of behind the meter generation resources.

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