NARUC

National Association of Regulatory Utility Commissioners

Demand Flexibility within a Performance-Based Regulatory Framework

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About This Paper

The jointly formed National Association of State Energy Officials (NASEO)-National Association of Regulatory Utility Commissioners (NARUC) Grid-Interactive Efficient Buildings (GEBs) Working Group released the report *Roadmapping: A Tool for States to Advance Load Flexibility and Grid-Interactive Efficient Buildings* in 2021.[1] The 2021 report explored various tools available for states to advance load flexibility and GEBs, aimed at State Energy Offices, Public Utility Commissions (PUCs), and other state and local agencies. This paper builds on past insights with a closer examination of demand flexibility (DF) barriers and implementation within a performance-based regulatory framework. As more complex forms of DF are introduced, regulatory frameworks can capture the impacts and potential benefits of new demand-side technologies. Specifically, this paper examines regulatory strategies that may be useful for state regulators seeking to advance DF and GEB policies.

- The introduction presents the various components of DF and explores how applications of performance-based regulation (PBR) can advance DF through better alignment and cohesion between policy goals and a utility's business decisions.
- The second chapter explores the general evolution of regulatory approaches for tracking and incenting more advanced forms of energy savings, including DF.
- The third chapter outlines a staged process for establishing PBR with an examination of the various components for successful implementation.
- The fourth chapter examines three case studies for states that are currently working to establish DF initiatives within a PBR framework.
- The final chapter includes insights and lessons learned that can inform the utility regulatory community as they navigate this emerging territory.

Related NARUC Efforts

Several PUCs and stakeholders are exploring PBR tied to policy goals as an alternative or complement to traditional ratemaking. This regulatory framework connects the achievement of specified objectives to utility performance and can include a collection of performance incentive mechanisms (PIMs) with supporting metrics or formulas that measure a utility's progress toward an objective and tie it to financial rewards or penalties (e.g., adjustments to allowed revenues). NARUC supports a variety of initiatives to examine approaches for valuing utility and customer investments, in coordination with the NARUC Staff Subcommittee on Rate Design. NARUC also facilitates the PBR State Working Group, which supports commissioners and staff who wish to explore the application of PBR for balancing the public's interests with a utility's investments. NARUC members should contact Elliott Nethercutt, enethercutt@naruc.org, for more information and to join the PBR State Working Group.

1 "*Roadmapping: A Tool for States to Advance Load Flexibility and Grid-Interactive Efficient Buildings*", May 2021. https://naseo.org/data/sites/1/documents/publications/NASEO-GEB-Roadmapping-Final.pdf.

1. Introduction

Grid-Interactive Efficient Buildings and Demand Flexibility

The decarbonization of the electric sector has involved a relatively rapid transformation of the resource mix in context of the system's 140-year history. In the absence of a national energy policy, most of these changes have been implemented at the state level, with legislation or regulatory initiatives that have established various energy and emissions targets. Since the first renewable portfolio standard was established in 1983, state policies have contributed to the deployment of more carbon-free resources, as well as investments in energy efficiency (EE). Currently, 30 states and the District of Columbia have established mandatory portfolio standards, ten of which have 100 percent clean energy or greenhouse gas (GHG) emission reduction targets for electric generation.[2] Renewable resources (often variable in nature) have been the fastest-growing energy sources in the United States, increasing 42 percent from 2010 to 2020 (up 90 percent from 2000 to 2020).[3] This trend is widely projected to continue, as U.S. Energy Information Administration's *2022 Annual Energy Outlook* demonstrates in all cases that renewable energy will be the fastest-growing energy source through 2050.[4]

A system with more variability on the supply-side can be supported by more responsive demand-side resources. Specifically, leveraging DF technologies can enable customers to reduce, increase, shift, or modulate electricity usage to support grid stability, to lower costs, and to create a more efficient system. New DF programs can leverage existing technologies to allow customers to modify their behavior in the 129 million buildings that consume 75 percent of U.S. electricity and contribute to 35 percent of annual U.S. carbon emissions.[5] GEBs can use DF (e.g., sensors, analytics, smart controls) to allow customers to adjust electricity use in response to prices, utility signals, and/or grid conditions.[6] According to U.S. Department of Energy projections, GEBs "have the potential to deliver between US$100 and US$200 billion in savings to the U.S. power system and cut CO2 emissions by 80 million tons per year by 2030, or 6 percent of total power sector CO2 emissions."[7] The wide-scale deployment of smart technologies in homes and offices, combined with well-designed utility or third-party programs, can enable utilities and distribution grid operators to leverage DF technologies and GEBs to reduce generator ramping needs and potentially offer additional grid services at the distribution level (**Figure 1**).

Implementing DF through an effective regulatory framework that creates collaborative utility programs can ultimately lower customer costs, enhance system resilience, and reduce GHG emissions. Regulators have been working with electric utilities to encourage the advancement of programs that will better inform customers about their electricity use to encourage behavioral changes that reduce or shift electricity consumption. Demand-side management (DSM), including EE and demand response (DR) programs, have been underway throughout the country for several decades.

2 Congressional Research Service. "A Brief History of U.S. Electricity Portfolio Standard Proposals." Updated February 24, 2021. https://crsreports.congress.gov/product/pdf/IF/IF11316.

3 Center for Climate and Energy Solutions. "Renewable Energy at a Glance." https://www.c2es.org/content/renewable-energy/.

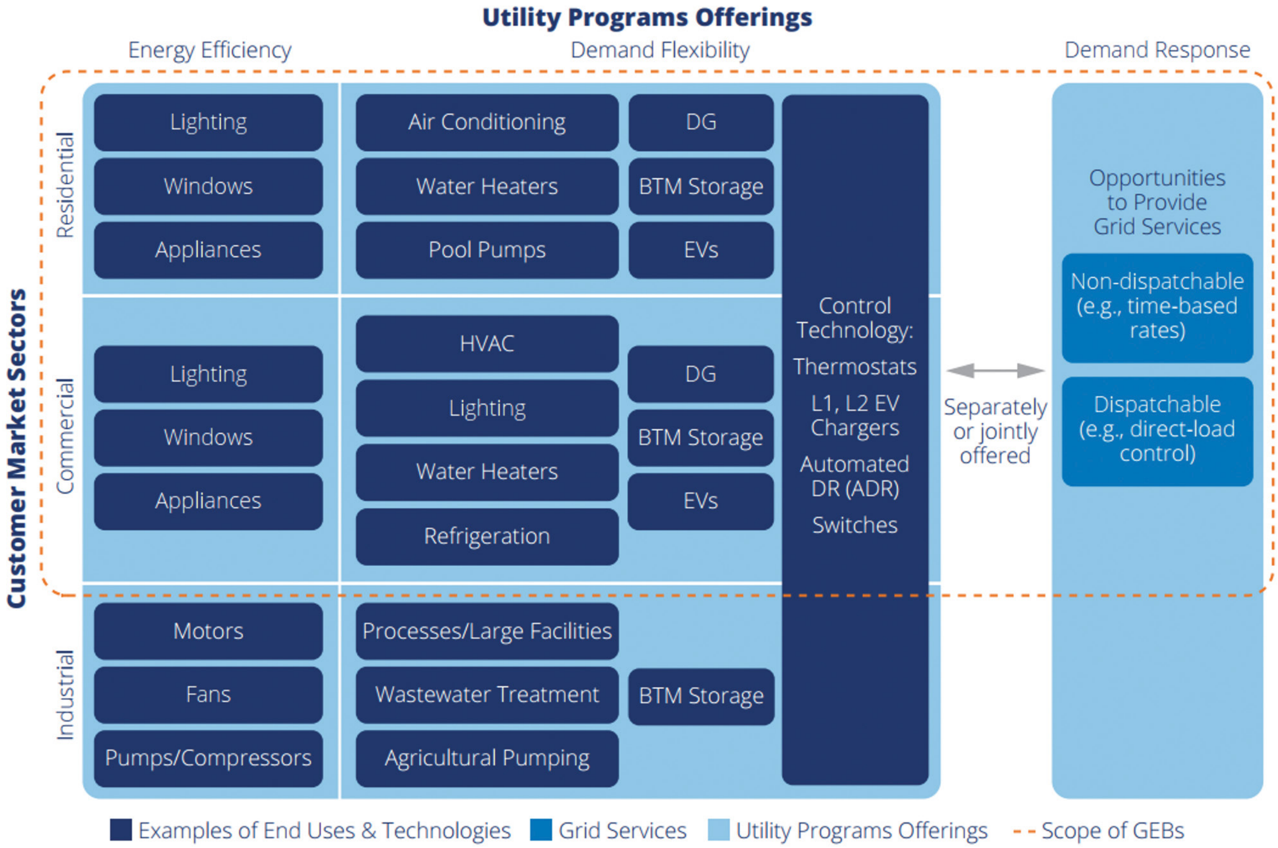
4 U.S. Energy Information Administration. "AEO2022 Narrative," March 2022, p. 6. https://www.eia.gov/outlooks/aeo/narrative/pdf/AEO2022_Narrative.pdf.

5 U.S. Department of Energy, "Meet DOE's Newest Connected Communities of Grid-Interactive Efficient Buildings," October 13, 2021, https://www.energy.gov/eere/buildings/articles/meet-does-newest-connected-communities-grid-interactive-efficient-buildings.

6 NASEO-NARUC Grid-Interactive Efficient Buildings Working Group. https://www.naseo.org/issues/buildings/naseo-naruc-geb-working-group. Demand flexibility (DF) has also been referred to as load flexibility. The American Council for an Energy-Efficient Economy (ACEEE) has also introduced the term "strategic demand reductions," defined as "a subset of energy efficiency and demand response measures, reducing demand at specific times to optimize the electricity system," https://energyinnovation.org/wp-content/uploads/2020/02/Performance-Incentive-Mechanisms-for-Strategic-Demand-Reduction.pdf. The Alliance to Save Energy uses the term "active efficiency," https://activeefficiency.org/.

7 U.S. Department of Office of Energy – Efficiency & Renewable Energy. "DOE's National Roadmap for Grid-interactive Efficient Buildings." May 18, 2021. https://www.energy.gov/eere/articles/does-national-roadmap-grid-interactive-efficient-buildings.

Figure 1: Utility-Coordinated EE + DF (+ DR) Programs and GEBs[8]

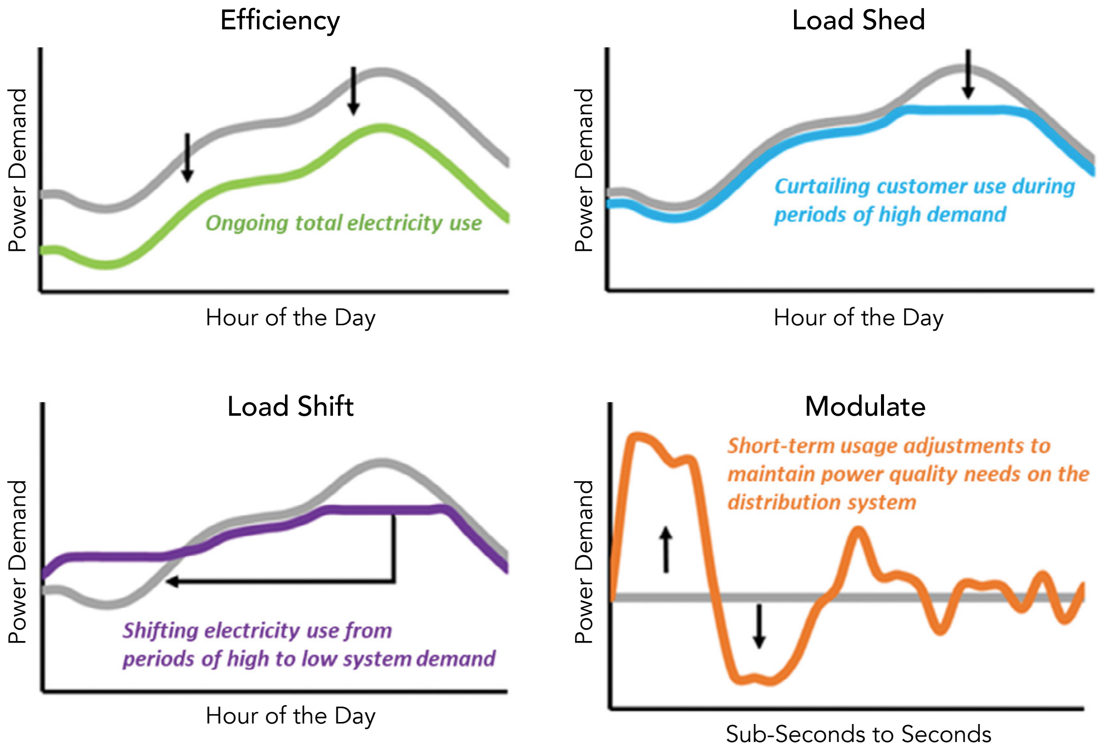


- **Demand Response:** Programs are primarily incentive-based and include reductions in dispatchable energy (e.g., direct load control, interruptible rates, demand bidding/buyback, and emergency DR), with some indicators for time-based rates. DR can be tariff-based, often with different levels of dispatchability.[9]
- **Energy Efficiency,:** Generally, aim to reduce overall electricity consumption (i.e., kWh) across different customer classes; sometimes with attention paid to reducing peak demand (kW).
- **Demand Flexibility:** Technologies can enable customers to move beyond traditional EE programs (reducing overall usage) to shift, shed, increase (at specified times and/or locations), or modulate electricity usage to support grid stability, lower costs, and create a more efficient system (**Figure 2**).

8 Smart Electric Power Alliance, "Accelerating Coordinated Utility Programs for Grid-Interactive Efficient Buildings," July 2022, p. 11, https://sepapower.org/resource/case-studies-for-accelerating-coordinated-utility-program-for-grid-interactive-efficient-buildings/.

9 Guernsey, M., Everett, M., Goetzler, B. Kassuga, T., Reed Fry, N. Langner, R. "Incentive Mechanisms for Leveraging Demand Flexibility as a Grid Asset" National Renewable Energy Laboratory (NREL). National Renewable Energy Laboratory (NREL). P. iv. https://www.energy.gov/sites/default/files/oeprod/DocumentsandMedia/DOE_Benefits_of_Demand_Response_in_Electricity_Markets_and_Recommendations_for_Achieving_Them_Report_to_Congress.pdf.

Figure 2: Outcomes of Effective DF[10]



Peak load reduction, provided by both load shedding and load shifting, are important aspects of DF that can offer multiple benefits to both the utility and the customer. Utilities avoid higher peak-period prices (ultimately recovered from customers) and can possibly defer or avoid costly capital investments that would otherwise be needed to meet future peak demand.[11] Peak load reductions in coordination with DF technologies will be particularly important with the proliferation of distributed energy resources (DERs) and variable renewable energy, allowing utilities to more effectively and reliably assess system demands to see when and where DERs and DSM can contribute to system stability.

DF can enable GEBs to achieve savings by altering electricity usage through direct control, price signals, or other incentives. In particular, advanced metering infrastructure (AMI) has enabled more sophisticated tracking of customer consumption and communications. In some cases, utilities can utilize AMI to observe electricity usage in near real-time, optimize demand-side programs, and record transactions for pay-for-performance energy savings. Advanced meters were initially used to create efficient utility operation to wirelessly measure customer usage for billing purposes. More recently, utilities are starting to leverage additional AMI capabilities to deploy newer demand-side programs, described in **Table 1**.[12]

10 NASEO-NARUC Grid-Interactive Efficient Buildings Working Group. https://www.naseo.org/issues/buildings/naseo-naruc-geb-working-group. Figure modified by NARUC staff.

11 B. Baatz, G. Relf, and S. Nowak, "The Role of Energy Efficiency in a Distributed Energy Future," ACEEE, 2018.

12 A. Satchwell, P. Cappers, L. Schwartz, and E.M. Fadronc, *A Framework for Organizing Current and Future Electric Utility Regulatory and Business Models* (LBNL-181246), Lawrence Berkeley National Laboratory, Berkeley, CA, June 2015, p. 13. https://www.osti.gov/servlets/purl/1248921.

Table 1: DF Implementation with AMI

DF Program	Description	AMI Need
Time-Variant Pricing	Utilities can charge different rates at different hours to reflect system conditions. Some utility programs include:[13] • Time-of-use (TOU) • Critical peak pricing • Peak-time rebate • Variable peak pricing • Real-time pricing Programs have reduced average electricity consumption by 2.1 percent and reduced average peak consumption by 16 percent.[14] In some surveys, these programs and rate designs are preferred over standard approaches.[15]	Required for TOU pricing to provide real-time price singles at different system nodes
Pay-for-Performance	Customers who opt to participate are paid by the utilities for the savings realized by reduced electricity usage over a specified time. The deployment of advanced meters allows residential customers to access these programs that were previously only available for larger customers. For residential customers, data is aggregated by third parties into project portfolios. These third-party aggregators are responsible for designing economic programs that are profitable and also create the desired customer behavior.	Required for residential customers
Real-Time (direct) Feedback	This type of technology enables customers to monitor real-time energy usage via in-home displays, integrated thermostats, web portals, or mobile apps. Some utility programs using mobile apps and web portals have demonstrated short-term savings of 5–20 percent.	Required for communication with customers

Performance-Based Regulatory Frameworks

State utility commissions have varying approaches for compensating utilities for the services they provide, based on establishing a rate of return and associated rates charged to customers. Utility regulator deliberations involve careful considerations for stabilizing the utility's revenue stream, as well as the rates paid by customers. Within these two critical components of a rate case, commissions weigh the impacts of capital investments and public policy goals, including efficiency programs, GHG emission reduction efforts, and the reliability of the electric system. Rate design is commonly structured so that a customer's utility bill (and a utility's revenue collection) is primarily determined by the amount of electricity consumed (utility's volumetric retail sales).[16] A traditional cost-of-service (COS) structure results in a "throughput incentive": a reduction in volumetric retail sales by the utility negatively impacts profits.[17] This paradigm can motivate a utility to overinvest in capital

13 B. Fitzjarrald and S. Patnaude, "6 DSM Program Types That Benefit from AMI," E-Source, November 2021, https://www.esource.com/601211hiym/6-dsm-program-types-benefit-ami.

14 Based on an ACEEE assessment of 50 programs with various rate structures; B. Baatz, "Rate Design Matters: The Intersection of Residential Rate Design and Energy Efficiency" (Report U1703), ACEEE, March 2017, p. vi, https://ipu.msu.edu/wp-content/uploads/2017/07/ACEEE-Electricity-Rate-Design-2017.pdf.

15 B. Fitzjarrald and S. Patnaude, "6 DSM Program Types That Benefit from AMI," E-Source, November 2021, https://www.esource.com/601211hiym/6-dsm-program-types-benefit-ami.

16 "Current and Future Electric Utility Regulatory and Business Models" (LBNL-181246), Lawrence Berkeley National Laboratory, Berkeley, CA, June 2015, p. 7–8, https://www.osti.gov/servlets/purl/1248921.

17 D. Moskovitz, "Profits and Progress Through Least Cost Planning," Washington DC: NARUC, https://www.raponline.org/wp-content/uploads/2016/05/rap-moskovitz-leastcostplanningprofitandprogress-1989-11.pdf.

resources to maximize opportunity for additional profits.[18] Accordingly, the COS structure can conflict with policy goals to advance EE and DF.

Regulators (and policymakers) continue to face several hurdles when designing policies to elicit the intended response from utilities. The introduction or expansion of DF (or EE programs) ultimately reduces volumetric electricity sales, which can lead to lost utility revenues in the near term. DF investments also fail to provide utilities with a rate of return offered by tangible infrastructure investments (e.g., power plants) and ultimately can "impact utility profit motivation by reducing the opportunities for the utility to invest in assets."[19] Regulators can be further hindered in encouraging DF due to asymmetrical access to detailed customer demand information (e.g., load shapes and hourly usage), which is useful for tracking utility progress in implementing demand-side saving initiatives. Granular data has often been difficult to collect, store, analyze, and transfer in a way that aligns with traditional regulatory approaches.

PBR offers an alternative framework that ties utility revenue to performance on desired outcomes to align the profit motivations of a utility to public policy goals. Such approaches can include moving financial motivations away from investing in capital expenditures (e.g., building a new power plant) to exploring demand-side opportunities that reduce or shift electricity consumption.[20] This outcome is achieved by allowing utilities to collect financial incentives for achieving various DF-related goals with rewards tied to metrics other than the utility's volumetric electricity sales. As an example, a regulator could tie a utility's revenues to a metric other than kWh safely delivered, such as lumens[21] of light as the performance metric. In this hypothetical case, the utility would seek to maximize the efficiency of light bulbs used by customers to provide the most lumens for the least amount of electricity.[22]

Most state commissions continue to regulate largely within the COS framework, but often utilize various PBR tools, including revenue decoupling, forward-looking test years, and PIMs.[23] Performance incentives are frequently a key component of PBR, enabled by regulators establishing metrics and associated targets and measuring a utility's progress toward them. In this model, (a portion of) a utility's profit will ultimately depend on its demonstrated ability to achieve a given target, measured quantitatively. This process is discussed further in Chapter 3.

Currently, 19 states and the District of Columbia have initiated—or are in the process of initiating—a PBR framework for utility compensation (**Figure 3**).[24]

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18 B. Terzic, "The Interface Between Utility Regulation and Financial Markets," Washington DC: Berkeley Research Group/NARUC, November 2018, p. 3, https://pubs.naruc.org/pub/8BA0B811-DACC-6863-1992-9188F70783AC.

19 A. Satchwell, P. Cappers, L. Schwartz, and E.M. Fadronc, "A Framework for Organizing Current and Future Electric Utility Regulatory and Business Models" (LBNL-181246), Lawrence Berkeley National Laboratory, Berkeley, CA, June 2015, p. 16, https://www.osti.gov/servlets/purl/1248921.

20 C. Holden, "More States Explore Performance-Based Ratemaking, but Few Incentives Are in Place," Greentech Media, June 13, 2019, www.greentechmedia.com/articles/read/morestates-explore-performance-based-ratemaking-but-few-incentives-in-plac.

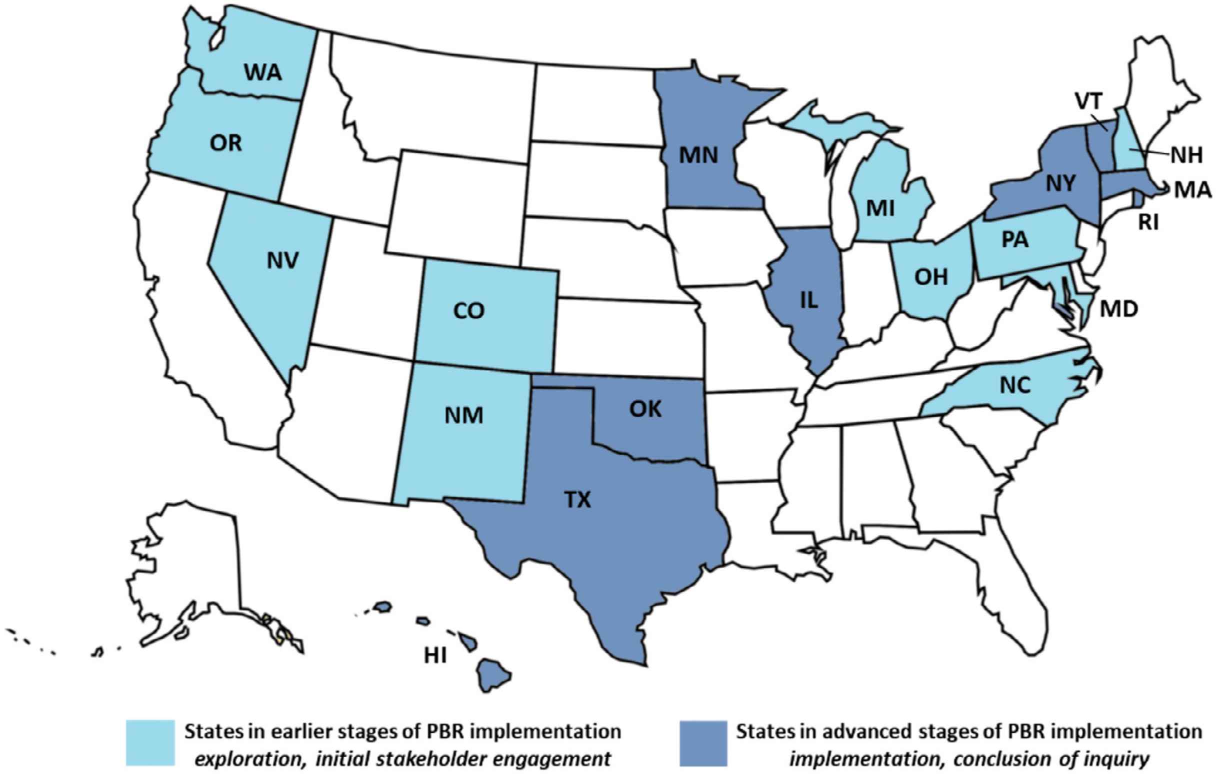
21 Lumens measure how much light you are getting from a bulb. For more information, see https://www.energy.gov/energysaver/lumens-and-lighting-facts-label.

22 P. Fox-Penner, "Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities," 2010.

23 M. Whited, T. Woolf, and A. Napoleon, "Synapse Energy. Utility Performance Incentive Mechanisms," Western Interstate Energy Board, March 2015.

24 Regulatory Assistance Project / NARUC PBR State Working Group. "Performance-Based Regulation for Resilience." Littell, D., Shur, B. June 24, 2021. https://www.raponline.org/wp-content/uploads/2021/06/rap_littell_naruc_pbr_resilience_2021_jun_24.pdf.

Figure 3: State-by-State Status of Performance-Based Ratemaking in the United States[25]



Seventeen of those states and Washington DC also have enacted policies directing the utility sector to reduce emissions from the electricity sector.[26] However, Hawaii is the only state to discontinue COS regulation and fully leverage a PBR approach.[27]

The next chapter explores how regulatory approaches for incenting EE and other types of demand savings has changed since its introduction in the 1970s.

25 InsightSeries, "Regulatory Evolution for a Decentralized Electric Grid: State of Performance-Based Ratemaking in the U.S.," June 2019, https://enerknol.com/regulatory-evolution-for-a-decentralized-electric-grid-state-of-performance-based-ratemaking-in-the-u-s/. Modified/updated by NARUC staff.

26 G. Wilson, C. Felder, and R. Gold, "States Move Swiftly on Performance-Based Regulation to Achieve Policy Priorities," Rocky Mountain Institute, March 2022, https://rmi.org/states-move-swiftly-on-performance-based-regulation-to-achieve-policy-priorities/.

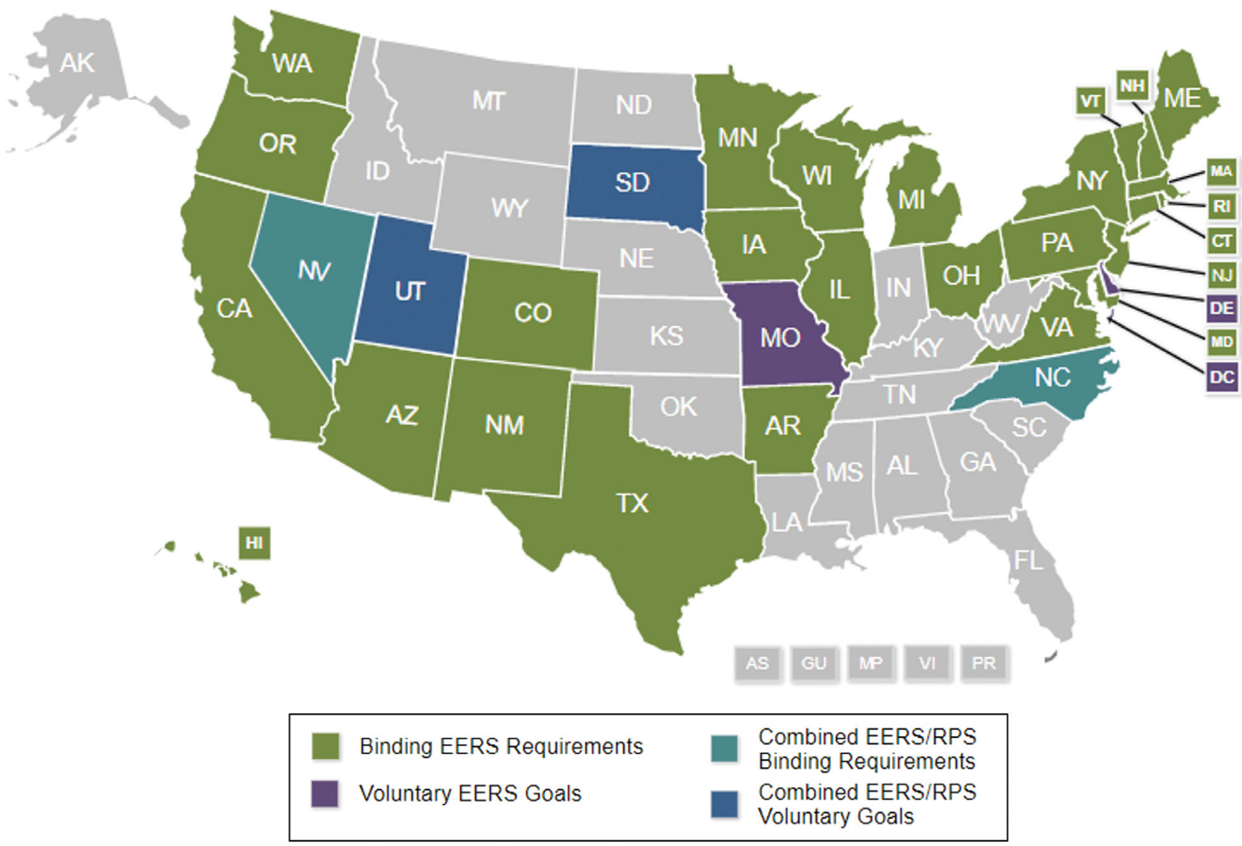
27 Ibid.

2. The Ongoing Evolution of Regulatory Approaches for Incenting Energy Savings towards Demand Flexibility

This chapter explores the evolution of regulatory approaches for incenting more advanced forms of energy savings, including DF. As more complex forms of DF are introduced, regulatory frameworks can be enhanced to capture the impacts and potential benefits of new demand-side technologies.

Regulatory commissions and electric utilities have been providing pathways for customers to reduce electricity use through improved EE since the late 1970s when global oil production fell and prices spiked. By the end of the 1990s, EE became part of the resource portfolio for many utilities throughout the country.[28] Throughout the 2000s, more than 25 states adopted EE resource standards (EERSs) that required utilities or third-party program administrators to achieve certain levels of annual megawatt-hour savings as a percent of sales.[29, 30] Aside from Michigan and Minnesota, compliance with these EE requirements is ensured by the PUC.[31] Today, over 30 states have successfully implemented EERS programs (**Figure 4**).[32]

Figure 4: States with EERSs or Voluntary Targets as of 2021[32]



28 D. York, P. Witte, S. Nowak, and M. Kushler, "Three Decades and Counting: A Historical Review and Current Assessment of Electric Utility Energy Efficiency Activity in the States," ACEEE, p. iii, https://www.aceee.org/research-report/u123.

29 ACEE Energy Efficiency Resource Standards, https://www.aceee.org/topic/eers.

30 U.S. Energy Information Administration, "Today in Energy," https://www.eia.gov/todayinenergy/detail.php?id=32332#:~:text=Since%20Texas%20became%20the %20first,states%20have%20adopted%20an%20EERS.

31 A. Downs and C. Cui, "Energy Efficiency Resource Standards: A New Progress Report on State Experience" (Report Number U1403), April 2014, p. 8, https://www.aceee.org/research-report/u1403.

32 National Conference of State Legislatures (NCLS). "Energy Efficiency Resource Standards." 2021. https://www.ncsl.org/research/energy/energy-efficiency-resource-standards-eers.aspx.

EE programs vary widely from state to state, but implementation typically involves the following:

1. The establishment of a **baseline for electricity consumption**.
2. A **program target** (or multiple targets) of desired savings relative to projections with and without program implementation. Targets can be designed in terms of energy savings (MWh), or as a percentage reduction from "business as usual" projections of sales.
3. Implementation of an EE program is executed by a **program administrator,** a utility or third party that is usually overseen by the commission.
4. Regulators often determine an **evaluation method**, typically involving measurement and verification (M&V) tools to assess the program's impact (e.g., gross savings vs. net savings).[33]
5. Commissions can also determine the **qualifying savings** that program administrators can count toward a target.
6. Finally, regulators often create **reporting requirements** for applicable utilities or program administrators, specifying the frequency of reports or type of information that must be included.

Energy savings programs are not limited to these components; utilities and commissions often develop additional program features to address provisions within the legislative framework that was provided in their state. Regulators frequently invite input from a variety of stakeholders and subject matter experts to drive certain program aspects.

For at least three decades, regulators have been exploring approaches to incent utilities to strive for efficiency targets. Strategies have included: multiyear ratemaking frameworks (allowing for rate adjustments between formal rate cases); revenue-capped PBR approaches for EE focused on controlling customers' total energy bills rather than per-unit prices; decoupling[34] of revenues from sales to incentivize utility investments in energy savings; allowing utilities to recover investments in EE by treating these investments as capital expenditures within a rate case or by including program costs in the rate base to be capitalized similar to other resource investments;[35] and PIMs for achieving energy savings above targets. These alternative ratemaking approaches, combined with other state-specific policies, have resulted in notable energy savings.

According to the American Council for an Energy-Efficient Economy (ACEEE), utilities spent approximately US$8.4 billion nationwide in 2019 on efficiency programs and saved 26.9 million MWh of electricity.[36] ACEEE's 2020 Utility Scorecard, assessing the 52 largest U.S. electric utilities across a range of EE metrics, found:[37]

- **Energy savings are increasing:** Among 51 observed utilities in 2017 and 2020, first-year energy savings increased by more than 3.2 TWh or 20 percent.[38] Peak demand savings also increased by more than 450 MW, which aligned with an increase in savings programs offered by utilities.

33 M. Kushler, S. Nowak, and P. Witte, "Examining the Net Savings Issue: A National Survey of State Policies and Practices in the Evaluation of Ratepayer-Funded Energy Efficiency Programs," ACEEE, http://www.aceee.org/research-report/u1401.

34 Office of State and Community Energy Programs. U.S. Department of Energy. "Energy Efficiency Policies and Programs State and Local Solution Center - Decoupling and Utility Business Models." https://www.energy.gov/eere/slsc/energy-efficiency-policies-and-programs#:~:text=Decoupling%20is%20a%20rate%20adjustment,of%20providing%20service%20to%20customers.

35 A. Downs and C. Cui, "Energy Efficiency Resource Standards: A New Progress Report on State Experience" (Report Number U1403), April 2014, p. 2, https://www.aceee.org/research-report/u1403.

36 Berg, W., Cooper, E., Jennings, B., Vaidyanathan, S. "The 2020 State Energy Efficiency Scorecard." American Council for an Energy-Efficient Economy (ACEEE). December 16, 2020. https://www.aceee.org/research-report/u2011.

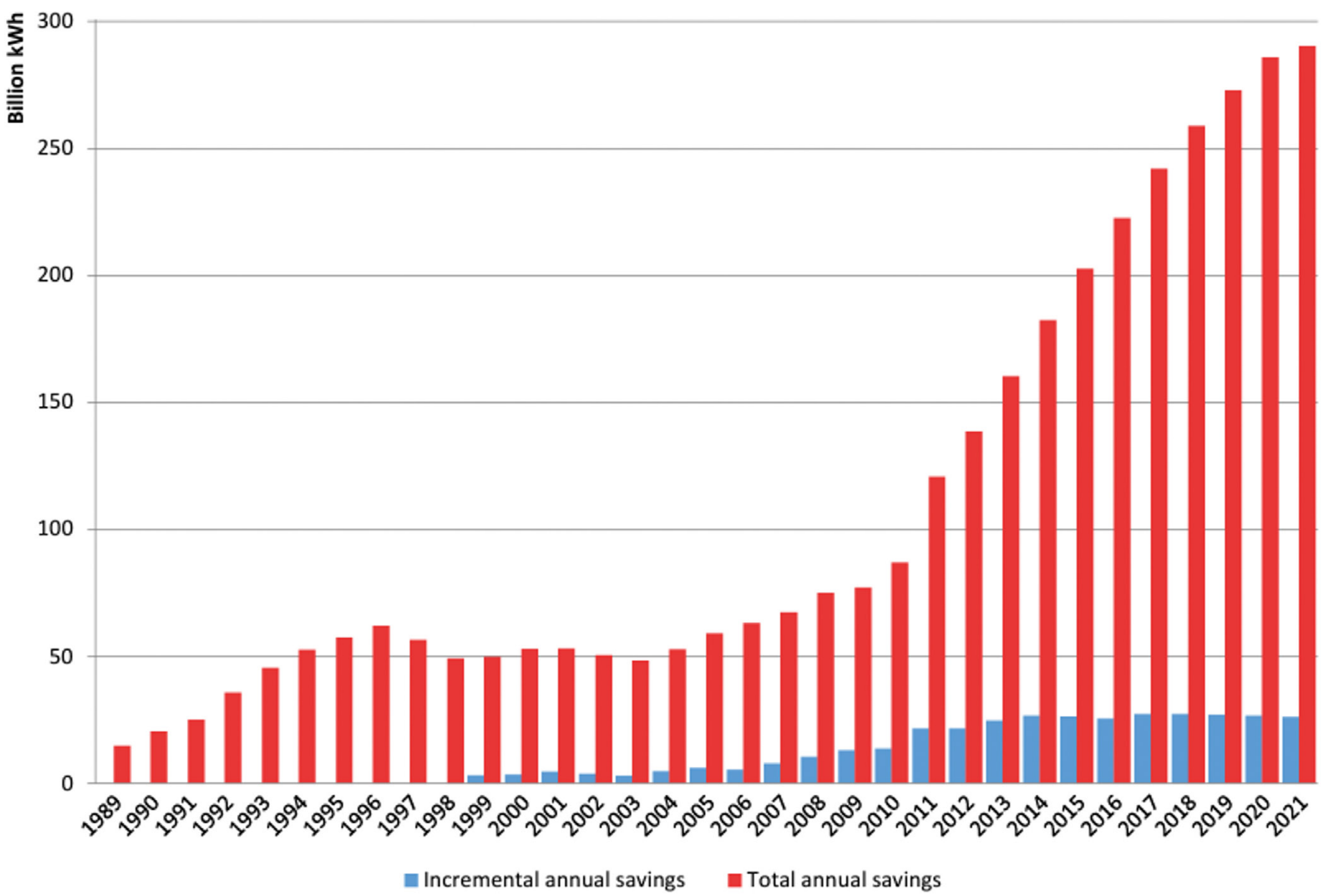
37 Cooper, E., Gold, R., Relf, G. "The 2020 Utility Energy Efficiency Scorecard." American Council for an Energy-Efficient Economy (ACEEE). February 20, 2020. https://www.aceee.org/research-report/u2004.

38 Seven utilities experienced savings decreases of more than 0.1 percent of sales.

- **Utilities are innovating to meet changing system needs:** Thirty-two utilities piloted new programs in 2018, including smart thermostats, online marketplaces for energy-efficient products, and DERs such as DR and storage systems. Utilities are also using GEB technologies and AMI to provide customer feedback on electricity consumption behavior.
- **Utility business models remain slow to change:** A growing number of utilities are participating in decoupling metrics and PIMs. While these policies incentivize robust efficiency performance, residential utility rate structures, an important tool for encouraging DF and energy-efficient behaviors, have remained largely unchanged since 2015.[39]

In their most recent *2022 State Energy Efficiency Scorecard*, ACEEE provided a ranking of states on policy and program efforts to save energy and pursue efficiency. The report included the total impact of ratepayer-funded EE programs, amounting to 290 million MWh of energy savings in 2021 (equivalent to approximately 7.6 percent of 2021 electricity consumption).[40] Total electricity savings by utility EE programs since 1989 are shown in **Figure 5**.

Figure 5: Annual Electric Savings from Utility-Sector EE Programs[41]



39 Cooper, E., Gold, R., Relf, G. "The 2020 Utility Energy Efficiency Scorecard." American Council for an Energy-Efficient Economy (ACEEE). February 20, 2020. https://www.aceee.org/research-report/u2004.

40 Berg, W., Cooper, E., Fadie, B., Hoffmeister, A., Jennings, B., Subramanian, S., Waite, M. "2022 State Energy Efficiency Scorecard." American Council for an Energy-Efficient Economy (ACEEE). December 6, 2022, p. 31, https://www.aceee.org/research-report/u2206.

41 Berg, W., Cooper, E., Fadie, B., Hoffmeister, A., Jennings, B., Subramanian, S., Waite, M. "2022 State Energy Efficiency Scorecard." American Council for an Energy-Efficient Economy (ACEEE). December 6, 2022, p. 31-32, https://www.aceee.org/research-report/u2206.

These findings illustrate the general trend that many utilities are experienced at achieving energy savings and beginning to drive DF deployment, but there are opportunities for more innovative utility business models and regulatory design to support further DF implementation. Improved M&V tools are important for both.

Tracking Demand Flexibility

As discussed in Chapter 1, utility programs and newer technologies for advancing DF continue to be deployed throughout the country. Utilities and regulators can leverage the improved visibility and insights from AMI to better understand the impacts of smart thermostats, controllable water heaters, and other DF interventions. More granular electricity usage insights can inform utilities and regulators and support the development of more complex rate design models that align with the more advanced demand-side technologies on the system. As this trend continues, advanced M&V tools are important for understanding the effectiveness of these technologies and rate designs.

The growing understanding of dual customer and grid benefits offered by DF have also led certain states, utilities, and stakeholders to explore modified approaches to traditional EE programs. While traditional EE program design generally encourages customers to reduce electricity consumption at any and all times, advanced EE and DF applications offer signals to shift when electricity is consumed. Achieving these more complex approaches will necessitate a change to the traditional EERS program attributes discussed above—particularly for program administrators, evaluation methods, and reporting requirements. In addition to offering customers a better understanding of their usage behavior, AMI and advanced M&V tools can support accurate compensation for customers and solution providers by tracking savings while costs fluctuate (e.g., on an hourly or more granular basis).

Some states are beginning to use advanced M&V tools to examine the impacts of DF programs. These M&V tools rely on AMI data while also leveraging advanced data analytics to conduct aggregated meter data analysis about the location and time of energy consumption changes. In pursuit of an incentive and compensation regime for EE and DF that does not rely solely on utility program administrators and ratepayer funding, the California PUC has adopted the concept of tracking energy savings using normalized metered energy consumption (NMEC), based on customers' AMI energy consumption data. NMEC is defined as "a set of tools and standards that, when applied to interval data, provides quantifiable and statistically significant reporting of normalized energy usage and energy savings due to an intervention, such as an EE project."[42] NMEC applications enable customers and utilities to isolate the impacts of a specific DF technology (i.e., an intervention), with an in-depth assessment of load shape and billing impacts (i.e., pre-performance/billing vs. post-performance/billing).

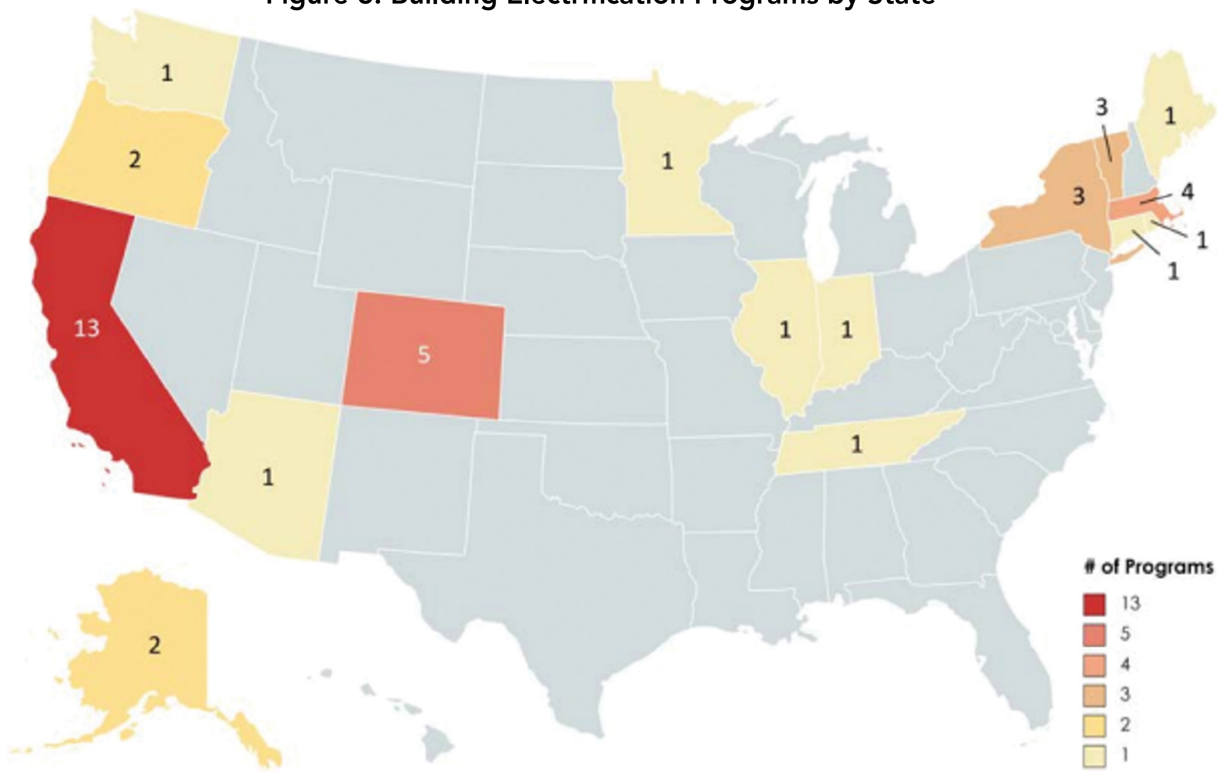
The California NMEC programs are supported by time-of-use (TOU) rates and can potentially leverage DF (and some GEB) technologies to allow customers to strategically benefit from higher payments for savings by adjusting consumption behaviors during certain periods. In October 2022, the California Energy Commission adopted additional updates to the state's load management standards that expand on customer access and visibility to electricity costs. The modifications to the existing standards will be effective on April 1, 2023, requiring larger regulated utilities and community choice aggregators to:

- Develop retail electricity rates that change at least hourly to reflect grid costs
- Maintain up-to-date rates in the Market Informed Demand Automation Server, a database for each utility's rate information
- Encourage customer adoption by providing education on time-dependent rates and automation technologies

42 Veregy. "An Introduction to Normalized Metered Energy Consumption (NMEC)." September 22, 2020. https://enpoweredsolutions.com/an-introduction-to-normalized-metered-energy-consumption-nmec/#:~:text=What%20is%20Normalized%20Metered%20Energy,as%20an%20energy%20efficiency%20project.

Several other commissions that formerly developed PIMs or other frameworks to advance EE are exploring more advanced DF applications that will involve moving away from incentivizing overall energy reductions to strategic electricity reductions and beneficial consumption at different times of day/night. Commissions and utilities see the potential for load growth due to beneficial electrification, including air-source and/or ground-source heat pumps, water heaters that use heat pump technology, and electric vehicle (EV) charging stations. Depending on the pace of deployment in various parts of the country, growth in electrification programs and policies has the potential to increase load beyond current projections. ACEEE's 2022 Report, Building Electrification: Programs and Best Practices, explores some of these developments and identified 16 states that are pursuing policies to advance electrification (**Figure 6**).

Figure 6: Building Electrification Programs by State[43]

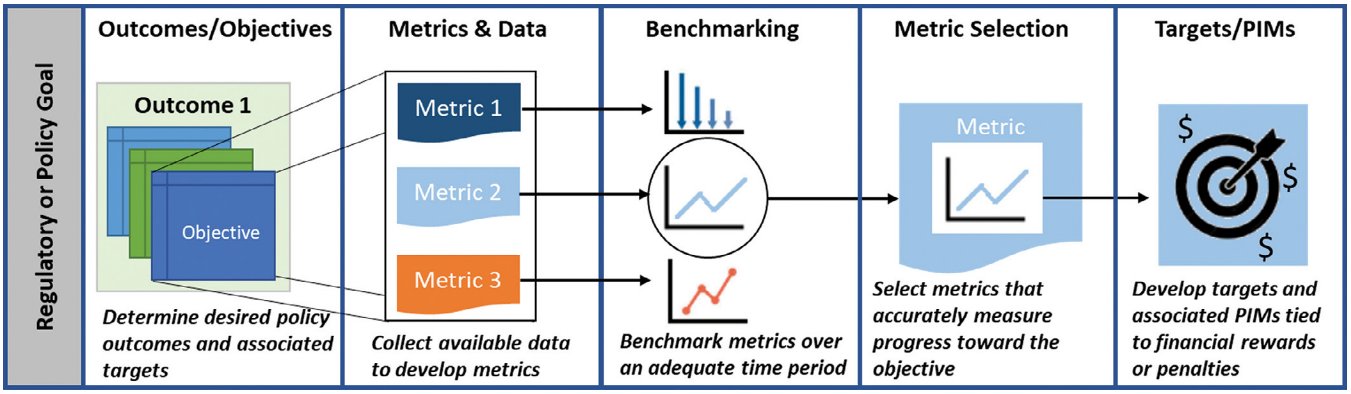


43 Cohn, C., Wang Esram, N. "Building Electrification Programs and Best Practices." American Council for an Energy-Efficient Economy (ACEEE). February 2022. https://www.aceee.org/sites/default/files/pdfs/b2201.pdf.

3. Advancing Demand Flexibility through a Performance-Based Regulatory Framework

Establishing a PBR model involves a multi-staged process of setting objectives (tied to policy goals), metrics (tied to objectives), targets (tied to metrics), and incentives/penalties (tied to the progress toward achieving targets). This process is summarized in **Figure 7**.

Figure 7: Performance-Based Regulatory Framework



Outcomes/Objectives

Objectives within the PBR framework will often align with state policy goals or regulatory priorities, with ultimate consideration for both the costs associated with achieving an objective, as well as the potential ratepayer benefits.[44] Goals can be quantitative or qualitative, but objectives will likely be quantitative.

In the 17 states with emissions reduction goals and PBR under development, some state policy goals might already be quantitative and directly translate to numeric objectives in the PBR framework. In states with state policy goals related to economic development or equity, the development of quantitative objectives will likely take more time and consideration.

At least 30 states have EE goals. Seven states have more specific demand-side goals and initiatives that specifically promote peak demand savings. EE, DR, and DSM can all be used to inform progress toward goals related to DF implementation.[45] More information on state-by-state outcomes and objectives related to DF are included in Chapter 3.

Metrics and Data

The selection of metrics and corresponding data is an important part of the PBR process, as this action sets the foundation for the subsequent development of targets and performance incentives or penalties. Depending on the specifically desired DF outcome or objective, regulators can develop metrics within or among the following three categories—noting various caveats associated with each (**Table 2**).

44 C. Goldenberg, D. Cross-Call, S. Billimoria, and O. Tully, "PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals," Rocky Mountain Institute, 2020, p. 25, https://rmi.org/insight/pims-for-progress/.

45 National Conference of State Legislatures (NCLS). "Energy Efficiency Resource Standards." 2021. https://www.ncsl.org/research/energy/energy-efficiency-resource-standards-eers.aspx.

Table 2: Activity-, Program-, and Outcome-Based Performance Incentives[46]

PIM Type	Purpose	Attributes
Activity-based	Track specific utility actions or decisions	• Not necessarily a reflection of the achievement of a desired outcome; focused instead on intermediate steps toward achieving an outcome • Could be helpful if direct measurement of an outcome is not possible
Program-based	Measure performance of specific utility programs	• Can be easier to measure than system-level metrics • Risk emphasizing specific programs, not allowing utility to optimize portfolio of options to support a particular outcome • Are more likely to interact and overlap with each other
Outcome-based	Focus on achievement of an outcome rather than specific actions	• Help address information asymmetry by allowing flexibility so utility can choose programs and/or technologies to meet specified outcomes most cost-effectively • Cost recovery for all utility actions may not be guaranteed • May be difficult to determine how utility decisions or external factors impacted desired outcome(s)

Selecting a metric and/or collecting data that does not align with the regulatory objective may result in unintended outcomes. Commissions can avoid these challenges by selecting metrics that prioritize objectivity and maximize isolation from exogenous influences.[47]

Commissions and utilities aiming to promote DF implementation may benefit from recent advancements in M&V technology that offers more detailed electricity consumption data. In some cases, these kinds of data can be benchmarked and aggregated to establish more advanced performance metrics within a performance-based approach, providing useful insights on the time and location of savings, or shifts in electricity consumption.

Benchmarking and Metric Selection

Reliable metrics will often be supported by a robust data set that can be used to formulate a baseline for comparison. Identifying the appropriate metrics and supporting data before establishing a baseline is an important part of the PBR process, which may require analysis of significant quantities (e.g., multiple years) of data.

This step is often dependent on clear communication and collaboration with the utility and relevant stakeholders to ensure the data requested and collected is aligned with the metric(s) and desired outcome. A data set that can be collected with consistency and will not be heavily impacted by exogenous factors will also promote more reliable trending and benchmarking. Tracking historical data, examining the progress of other utilities, and modeling policy trajectories are all ways of assessing the usefulness of both the metric and the underlying data.

46 C. Goldenberg, D. Cross-Call, S. Billimoria, and O. Tully, "PIMs for Progress: Using Performance Incentive Mechanisms to Accelerate Progress on Energy Policy Goals," Rocky Mountain Institute, 2020, p. 24, https://rmi.org/insight/pims-for-progress/.

47 Table developed by NARUC staff using information from: M. Whited, T. Woolf, and A. Napoleon, *Utility Performance Incentive Mechanisms—A Handbook*, Synapse Energy Economics, Inc., March 2015, p. 30.

Finally, metrics that are easy to interpret and verify can help improve alignment between the commission, utility, impacted stakeholders, and interested customers, while also leading to an easier development of targets and incentives.

Targets and PIMs Development

Final steps in the PBR development process involve the creation of targets and PIMs with financial implications. After a reliable baseline has been established, regulators can then coordinate with the utility and stakeholders to determine a pathway from the baseline toward a specified policy goal, expressed as a target, and financial rewards or penalties.[48]

Combining industry expert advice and direct feedback from various commission staff, the following design considerations might aide commissions in the development of targets:[49]

- Align targets with objective(s)/policy goal(s)
- Consider the utility's size, structure, existing business model, and current resource mix
- Review the status of progress/actions the utility is already taking
- Conduct costs/benefit analyses of the utility's target achievement
- Encourage stakeholder input and understanding of the target
- Include a neutral range ("deadbands") with no financial penalties or rewards; allow for some inherent uncertainty and impacts outside of a utility's control
- Incorporate longer time periods or averaging of multiple years toward target achievement
- Allow for target modification to incorporate impacts of ongoing industry and regulatory evolution

Regardless of metric type (discussed above) and selected target, the process for establishing PIMs involves careful determination of the financial rewards to incentivize utility action toward reaching the outcome, while also assessing potential penalties for inaction or underperformance.

PIMs can be implemented using a tiered approach that rewards the utility for measurable progress toward specified targets or penalizes the utility for failing to meet targets within an allotted timeframe. "Upside-only" PIMs provide only financial benefits for achievement of specified targets, while "downside-only" PIMs apply utility penalties when targets are not achieved.50 PIMs do not necessarily include both reward and penalty components, but each can be useful in driving a utility's investments and business decisions to achieve the intended outcomes.

The PIMs structure developed by the Hawaii PUC offers an example of both rewards and symmetrical penalties (in some cases) to motivate the utility to achieve a minimum degree of progress toward a given outcome (**Table 3**). The PIMs shown could support DF.

48 R. Katofsky, "Performance-Based Regulation State Working Group Expert Webinar: Establishing Metrics," Advanced Energy Economy, April 2022, Slide 6/37, https://www.youtube.com/watch?v=tJTiwVGfYyk.

49 M. Whited, T. Woolf, and A. Napoleon, *Utility Performance Incentive Mechanisms—A Handbook*, Synapse Energy Economics, Inc., March 2015, p. 30.

50 R. Gold, A. Myers, M. O'Boyle, and R. Grace, "Performance Incentive Mechanisms for Strategic Demand Reduction" (Report U2003), February 2020, p. 29, https://energyinnovation.org/wp-content/uploads/2020/02/Performance-Incentive-Mechanisms-for-Strategic-Demand-Reduction.pdf.

Table 3: PIM Rewards and Penalties—Hawaii[51]

PIM	Objective	Potential Reward	Penalty
RPS-A	Accelerate achievement of Renewable Portfolio Standards (RPS) goals	• $20/MWh 2021-2022 • $15/MWh 2023 • $10/MWh remainder of term	• $20/MWh for every MWh under the RPS
Grid Services	Expedite acquisition of grid services capabilities from DERs	• $1.5 million	• No penalty
Interconnection Approval	Improve customers' experience by incenting faster interconnection times for DER systems <100 kW	• $3 million	• Maximum penalty is $900,000
LMI Energy Efficiency	Encourage customer engagement, equity, and affordability by delivering energy savings for low-and moderate-income (LMI) customers	• $2 million	• No penalty
AMI Utilization	Promote customer engagement and DER asset effectiveness by accelerating the number of customers with advanced meters enabled to support time-varying rates and next generation DER programs	• $2 million	• No penalty

Technology, costs, and customer preferences often change over time, so a feedback loop can be especially useful for determining whether the selected metric(s) and corresponding target(s) are continuing to support the intended outcome. A PIM might need to be updated regularly to remain relevant, ensure obtainability by the utility, and offer value to the ratepayer. Performance targets and corresponding financial incentives are likely to be modified over time, but significant changes to the underlying data might create other challenges that may hinder a commission's ability to track a utility's progress.

Drawing from multiple sources, including government publications, input from commission staff, and other industry research organizations, four key tips have emerged for regulators to consider as they design PIMs:

- **Clearly define customer cost impacts:** Establish clarity in the potential impacts on customer bills, future rate increases, and the utility's revenue requirement. Evaluate impacts to low- and moderate-income (LMI) customers that may have more exposure to changes to the existing rate design. States can also create carve-out programs for low-income customers (e.g., Texas).
- **Ensure cost transparency and customer engagement:** Promote a transparent, simplified cost accounting structure for DF investments (e.g., EE interventions, smart meters, customer storage rebates). TOU and critical peak pricing rates can provide useful price signals for customers that can help change consumption behavior. Regulators can also encourage or require utilities to provide more granular information and insights on customer usage that can equip customers with the information needed to alter consumption, reduce bills, and potentially lead to improved distribution-level reliability.
- **Support data accessibility:** Ensure the data collected for a metric and corresponding PIM is accessible to the program administrator, the commission, and relevant stakeholders. Where states have third-party EE program administrators (e.g., DC, Hawaii, Minnesota, and Vermont) and utilities that separately support

51 NARUC Center for Partnerships and Innovation Performance-Based Regulation State Working Group. "Performance Incentive Mechanisms 101 Webinar." March 2021.Slide 22/44. https://pubs.naruc.org/pub/F8BBFA8E-1866-DAAC-99FB-E96833ABAC29?_gl=1*wldzov*_ga*NzQ3OTYxMDM5LjE2NTc1NTE5ODA.*_ga_QLH1N3Q1NF*MTY2MTkxNjgwOS40My4xLjE2NjE5MTc1NDEuMC4wLjA.

DR programs, collaboration and data sharing between the EE administrator and utility can be particularly important to support DF initiatives; establishing defined roles related to DF targets, implementation, and incentives will also be important.

- **Address utility concerns:** Utilities may express concerns that DF (particularly EE and DERs) and associated PIMs will generally reduce the volume of the utility's electricity sales and associated revenues/achieved profits. As a regulatory body designs PIMs, opportunities for utility participation and input in the PIM design can allow for better long-term results, striking the appropriate balance between allowing utility profits while also ensuring financial incentives are aligned with policy goals and customer affordability.

The following chapter examines three states, Hawaii, Colorado, and Vermont, that are highly ranked in ACEEE's 2020 State Scorecard and are also in various phases of PBR exploration and implementation.

4. Case Studies of States Currently Implementing Demand Flexibility through a PBR Framework

This chapter examines three states that are using a performance-based framework to implement DF initiatives, either within or outside of a rate case. These succinct case studies offer some insights into various barriers and early lessons learned; they are intended to support PBR understanding for other PUCs that are interested in advancing DF and related policies. Information being collected by each state and resulting impacts on savings are still emerging.

Hawaii, Vermont, and Colorado are at various stages of exploration and implementation. Hawaii and Vermont have made significant advances in recent years. Hawaii's commission is regulating the investor-owned utilities entirely within a PBR framework, while Vermont uses PBR for four of its 17 regulated utilities. The Colorado Commission assessed the viability of PBR in 2019–2020 and concluded that it would continue to build on existing performance-based mechanisms, with the immediate focus on encouraging GHG reductions. Xcel Energy, the state's largest regulated utility, is currently proposing several performance-based initiatives outside of their rate case.

Table 4 provides an overview of various DF initiatives that have been proposed or implemented within a performance-based framework. For Hawaii and Vermont, additional information is provided on progress in the various stages of the PBR framework model (see **Figure 7**).

The following information was collected through a combination of research and interviews with subject matter experts in the three states: Hawaii, Vermont, and Colorado. NARUC reviewed relevant dockets, a brief history of the state's experience with DF in a PBR framework, and latest developments or actions by the commission or utilities.

Hawaii

Dockets: Through Order No. 32054, filed April 28, 2014 (Docket No. 2007-0341); No. 2010-0037; No. 2018-0088 (Order No. 37507); Order No. 32054 (Docket No. 2019-0323); Order 38429; Order 37787.

Background and Framework: The Hawaii PUC initially explored DR a decade ago, emphasizing its importance through Order No. 32054, filed April 28, 2014 (Docket No. 2007-0341 is the DR policy statement). Docket No. 2019-0323 examines more specific and technical aspects of grid services from DERs/TOU rates (e.g., value of grid services, setting TOU rates, advanced inverter settings, etc.). A PBR framework was subsequently introduced to address utility business models with the intention of reducing capital bias and establishing performance incentives (both penalties and rewards) for policy initiatives that require additional attention from the utility (e.g., DER acquisition, AMI benefits, etc.).

Development of more recent PIMs within Hawaii's PBR framework involved the careful establishment of a baseline for each metric. This process required multiple data requests to ensure the commission was receiving data in a usable format that was well-understood and linked to a specific metric. Developing the appropriate metrics also required close coordination and communication between the commission, program administrator, and/or utility throughout the development of the data collection process. Another important factor was the establishment of regular reporting metrics on multiple data points, helping to increase data availability going forward and allowing for the commission to set future PIMs more easily. Prior to the current PBR framework, Hawaiian utilities and the commission were collecting data that tracked DER interconnection times, the number of customers enrolled in TOU rates, the number of customers with installed advanced meters, and number of customers with controllable water heaters.

Table 4: Status of DF Initiatives within a PBR Framework in Three States

State	Overview	Metrics & Data	Bench-marking	Metric Selection	Targets/ PIMs
HI	• Current PBR framework took effect June 2021[52] • Commission regulates entirely within a PBR framework • Latest series of PIMs approved in 2022[53] • Developed six DF-related objectives	Collected data for metric development for the Hawaii Electric Company[54]	Data trended over the course of 3 years for most PIMs	Selected 19 DF-related metrics	Targets developed for 8 metrics; financial incentives/ penalties tied to performance
VT	• First PBR case filed in 2009 by Green Mountain Power • Latest PBR efforts underway; initial metrics identified • Three DR-related objectives	Over 40 metrics have been identified	Benchmarking of metrics is underway	5–7 metrics will ultimately be selected and applied to four utilities	The 5–7 metrics will ultimately be tied to financial incentives/ penalties
CO	• Regulated utilities have used DSM performance incentives for many years; additional PIMs in development (outside of rate case) • Only largest regulated electric utility, Public Service Company of Colorado (dba Xcel Energy) has a DR initiative • Currently Xcel has incentives for energy savings only; Xcel has proposed a five-part incentive (including DR) with an incentive sharing mechanism in an active proceeding	Current data includes kWh energy savings, MW electric demand reduction, and DR attainment. Current metric for incentive is kWh annual electric energy savings.[55]	TBD	TBD	TBD

The Hawaii PUC has also worked with regulated utilities to address capital bias. Traditional demand-side management programs often lack incentive to increase investments, as the utility's investments have historically resulted in a simple passthrough. Hawaii Energy, a nonprofit organization, serves as the state's EE program administrator. Part of the newer PBR framework allows the utility to seek a return specifically on noncapital

52 State of Hawaii Public Utilities Commission. Performance Based Regulation. https://puc.hawaii.gov/energy/pbr/.

53 State of Hawaii Public Utilities Commission. Docket No. 2018-0088. Decision and Order No. 38429. https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A22F17B22248C03606.

54 There are three regulated utilities in Hawaii: Hawaii Electric Company, Hawaii Electric Light Company, and Maui Electric Company. All three are owned by a single parent company.

55 The proposed initiatives include all with the addition of an incentive tied to DR deployment (measured as energy kWh or MWh), and beneficial electrification (reporting includes avoided therms and emissions, potentially incremental and net load emissions, and proposed incentive includes percent of net benefits from beneficial electrification).

investments.[56] More recently, Hawaii is pursuing DR and DERs to provide services on a more granular level to assess how these resources can provide fast frequency response (advanced inverters), voltage control, and other support for grid stability.

Customers enrolled in programs are currently delivering 13.6 MW of capacity on Oahu and 1.5 MW on Maui. The utility and commission are monitoring and further researching the impacts of combined distributed solar and storage. The impacts of high penetrations of these resources may require updated guidelines on inverter settings to provide appropriate voltage support while considering possible negative impacts on customer output. It is also important to examine potential frequency impacts from widescale deployment of DERs.

The PBR proceeding is the result of a 3-year stakeholder process to establish the framework. Order No. 37507 was previously approved on December 23, 2020, and ultimately finalized on May 17, 2021. This order issued a decision and approving a portfolio of initial PIMs with corresponding scorecards and reported metrics. One of the primary goals of this framework is to align key objectives and identify challenges for utilities where past regulatory models have resulted in lacking progress toward specified policy goals.

The Hawaii PUC is embracing the PBR framework and has moved away from traditional COS rate structures. There is a 5-year multiyear rate plan; allowed revenues are adjusted annually for inflation, and there is a "customer dividend," an exceptional recovery mechanism for qualifying projects that have been approved. The utility must achieve a 75 percent minimum of the target but can only benefit from up to 125 percent of the maximum target, with financial incentives determined by percentages allocated to each objective.[57]

Hawaii Energy, the third-party EE administrator, also has multifactor PIMs that establishes project/program-specific shared savings mechanisms. Some DF programs are also addressed outside of rate cases as part of a surcharge or tracker for cost recovery. For example, Hawaii Energy could be funded by a separate surcharge.

Hawaii has technological limits for fully integrating DERs into the utility's operating practices, and the commission is working to resolve these challenges, as DERs will be critical for achieving the 100 percent renewable energy standard due to the land limitations of the islands.

Latest Developments: Hawaiian Electric, in coordination with the Hawaii PUC, established performance scorecards and metrics that were most recently updated in December 2020, covering the following topics: affordability; capital formation; cost control; customer engagement; customer equity; DER asset effectiveness; electrification of transportation; GHG reduction; grid investment efficiency; and interconnection experience. **Table 5** outlines the DF-related goals, established metrics, and associated targets and reporting frequency.

Hawaii is currently implementing four PIMs with associated financial rewards or penalties, including three for Hawaii Electric Company (grid services, LMI EE PIM, and AMI) and one for Hawaii Energy. The utilities also report separate scorecards and metrics that are considered "performance mechanisms" with no associated financial impacts. The PUC most recently adopted a new series of PIMs on June 17, 2022.[58] These finalized PIMs involved more performance details related to LMI energy, AMI utilization, and interconnection efficiency. The order also provided a portfolio of reported metrics.

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56 State of Hawaii Public Utilities Commission. Docket No. 2018-0088. Decision and Order No. 37507. See 84–86 https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A20L23B12153B01118.

57 National Conference of State Legislatures (NCLS). "Promoting Cost-Effective Utility Investment in Energy Efficiency." 2021. https://www.ncsl.org/research/energy/promoting-cost-effective-utility-investment-in-energy-efficiency.aspx.

58 Hawaii Public Utilities Commission, Decision and Order No. 38429; Public Utilities Commission; Docket No. 2018-0088. Decision and Order No. 38429. https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A22F17B22248C03606.

Table 5: Hawaii's PBR Framework (relevant to DF)[59]

Goal	Metric and Description	Target and Reporting Frequency Q = Quarterly, B = Biannual, A = Annual	
Customer Engagement	**Program Participation:** # and % of customers participating in qualifying Community Based Renewable Energy, DR, DER programs	30% of customers	Q
	Green Button Connect My Data: # and % of customers that have enabled information sharing	Equal to the percent of all customers delivering at least two benefits: 2021: 2.5–5% 2022: 10–15% 2023: 20–30%	Q
	Green Button Download My Data: # and % of customers that have downloaded data		Q
	TOU Participation: # and % of customers participating in time varying tariffs, by customer class		Q
	AMI Opt-Out: % of customers opting out of AMI	No target yet; dependent on initial performance	–
DER Asset Effectiveness	**Grid Services Capability:** % and total MW of DER systems capable of providing grid services	No target yet; dependent on initial performance	B
	Grid Services Enrollment: % and total MW of capable DER systems enrolled in grid services programs	No target yet; dependent on performance	B
	Grid Services Utilization: % and total MW of DER systems enrolled in grid services programs that are being utilized to provide grid services	No target yet; dependent on initial performance	B
	Curtailment: Total MW and MWh of curtailment from DERs, including partial curtailment or power reductions	No target yet; dependent on initial performance	B
Electrification of Transportation	**Fleet Electrification:** # of the company's passenger EV miles driven as a % of total passenger vehicle fleet miles driven	10% increase in EV miles as a share of total passenger vehicle miles	A
	Measured Electric Vehicles (EV) Load (Energy): Measurable energy (kWh) delivered to EV charging stations in approved EV tariffs by time period, to be expanded to include enrollment in any subsequently approved EV tariffs	No target yet; dependent on initial performance	A
	Estimated EV Load: Average demand (kW) attributable to measured EV charging in approved EV tariffs by hour, to be expanded to include any subsequently approved EV tariffs	Decrease in proportion of average demand (kW) attributable to measurable EV charging during on-peak hours	A
Grid Investment Efficiency	**Avoided transmission and distribution (T&D) Investment:** Total value ($) of deferred and/or avoided T&D capital investments due directly to the installation or acquisition of an NWA	No target yet; dependent on initial performance	A
	Non-Wires Alternatives (NWA) Total Cost: Total cost of NWA projects deployed by the utility or acquired through a customer program or competitive procurement	No target yet; dependent on initial performance	A

continued

59 Hawaii Electric. Performance Scorecards and Metrics. Performance Based Regulation (PBR) Scorecards and Metrics. https://www.hawaiianelectric.com/about-us/performance-scorecards-and-metrics.

Goal	Metric and Description	Target and Reporting Frequency Q = Quarterly, B = Biannual, A = Annual	
Interconnection Experience	**Total DER Interconnection Time:** Company's respective average (mean) total number of calendar days to interconnect DER systems < 100 kW in size, in a calendar year	2021: 115 days 2022: 100 days 2023: 85 days	A
Interconnection Experience	**Truck Roll Response Time:** Truck roll-related response times for meter change-outs for DER and non-DER customers	10 business days or 14 calendar days	A
Interconnection Experience	**Independent Power Producer (IPP) Interconnection:** For each IPP project with a Power Purchase Agreement (PPA) approved by the PUC	No target yet; dependent on initial performance	A
Interconnection Experience	**Interconnection Cost Overrun:** % of times the actual cost of interconnection has exceeded the estimated cost of interconnection for utility-scale IPP projects with a PPA approved by the PUC	No target yet; dependent on initial performance	A
Customer Equity	**LMI Customer Participation:** # and % of LMI customers participating in one of the following qualifying programs: CBRE/shared solar, TOU rates, DER, customer grid-supply, and DR	No target yet; dependent on initial performance	Q

Vermont

Dockets: 30 V.S.A. § 209; 20-0644-INV

Background and Framework: The Vermont PUC has made significant progress in implementing some aspects of PBR to advance DF. The commission began efforts toward "alternative" regulation in 2006, following Vermont statute 30 V.S.A. § 218. This enabled alternative regulation and established criteria for multiyear rate plans, allowing longer durations between rate cases if the utility is making progress toward achieving a policy goal. This alternative regulatory framework further allowed for utilities to modify certain rate components without a full review of the rate design, allowing more flexibility for offering new services to customers. Green Mountain Power filed the first PBR case in 2009.[60]

Two electric EE utilities deliver EE services to customers in the state:

- Efficiency Vermont (EVT) delivers EE programs throughout the state
- City of Burlington Electric Department provides EE programs in its service territory

EVT receives performance compensation based on the attainment of 3-year performance targets or quantitative performance indicators established by the PUC. Some quantitative performance indicators are minimums that result in reductions to EVT's compensation if not met, while others "scale up" with increased performance, as compared to the previous 3-year performance period. The current framework includes a shared savings incentive with PIMs currently in development (benchmarking metrics).

Latest Developments: Of the 17 regulated electric distribution utilities in Vermont, the commission has established DF-related metrics for four of them. The PUC is currently assessing metrics to establish benchmarks and eventually determine 5 to 7 metrics that would subsequently be tied to a performance-based mechanism with financial compensation. The PUC introduced a set of metrics for the largest utility, Green Mountain Power, with financial rewards. Program costs were reimbursed at a flat rate, while approximately half of the utility's profits were tied to meeting specific metrics. The utility is provided a limit on capital expenditures, along with a flow-through cost recovery tied to the actual energy supplied.

60 Vermont Biz. "GMP files performance-based regulation plan with Vermont PSB." December 30, 2009. https://vermontbiz.com/news/2009/december/30/gmp-files-performance-based-regulation-plan-vermont-psb.

The PUC issued an order on December 17, 2020 (Docket 20-0644-INV), approving 2019 Renewable Energy Standard compliance for all utilities. This included provisions for DF technologies—particularly EE. Vermont also introduced legislation to establish a process for measuring the effectiveness of innovative DF pilot programs related to flexible loads, dynamic load control, EVs, smart thermostats, and residential batteries.

Utilities are also offered funding for pilot programs, such as controllable heat pumps, virtual power plants, EVs, and residential storage. This includes allocation of funds for investment in these technologies, with allowance for related capital expenditures to earn a return on equity. Several Vermont utilities have completed pilots, while many are still underway.[61] An example includes the deployment of two-way communication chargers that allow a utility to temporarily disconnect EV chargers during periods of high demand or system stress. The utility will benefit from this investment by enabling energy savings during peak periods that will ultimately cover the charger's expense and in the longer term, allow the utility to collect revenue.

Energy storage has been particularly successful in Vermont, with an initial pilot program that allowed a utility's capital investment to purchase and install residential batteries to be used for load shifting. Green Mountain Power is leading this effort with over 5 MW of residential storage deployed, which is significant considering Vermont's geographic size and total energy usage. The benefits included payment for critical peak pricing with the Regional Network Service, which shifted annual capacity costs into energy-based rates. Customers were able to be called up to 60 times in a modeled year.[62] This residential storage program is moving from a pilot to a tariffed service due to its success in achieving DF. Batteries owned by the utility allow for the capital investment to be captured within rate base (currently, all batteries are Tesla, but customers can source from other qualifying providers). In this program, customers receive an upfront incentive, depending on whether and when the utility can call upon the storage resource.

The Vermont Electric Cooperative and Washington Electric Cooperative have partnered with Packetized Energy Management, a company that uses artificial intelligence to coordinate loads with either price signals or response to renewable generation output. This program is currently in effect for water heaters and in the earlier stages of implementation for heat pumps. During periods of higher output from variable resources (wind and solar), the utilities can activate these loads to absorb excess energy and provide system stability.

Additional Insights: Electrification is part of the Vermont's renewable energy standard, allowing utilities to demonstrate how electrification can reduce GHG emissions, as well as how the associated impacts can be tied to achieving various tiers of the state's renewable energy standard targets.

Most of the DF efforts in Vermont are aimed at addressing and flattening the sharp peaks. These efforts have been particularly successful so that flatter peaks are more common and high peaks are becoming more challenging to target. This can create complicated revenue challenges, as transmission investments are largely dependent on revenues during peak periods, with additional supports from energy prices across the ISO-New England footprint. Vermont continues to shift the focus of DF from monthly peaks, frequency regulation, and energy arbitrage to the vision of flexible loads that include balancing the integration of renewable resources and supporting reduced emissions from remaining GHG-emitting resources. This can be complicated by the challenge of assigning values and isolating the benefits of DF investments.

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61 Additional information is available in SEPA's 2022 report, *Accelerating Coordinated Utility Programs for Grid-Interactive Efficient Buildings: Practitioners' Perspectives*, https://sepapower.org/resource/accelerating-coordinated-utility-programs-for-grid-interactive-efficient-buildings-practitioners-perspectives/.

62 Vermont Public Service Department and Newgen Strategies and Solutions, LLC. "Rate Design Initiative / Distributed Energy Resources Study – Stakeholder Engagement Meeting #3." April 16, 2020. https://publicservice.vermont.gov/sites/dps/files/documents/RDI%233b_Wrkshp-Slides_041620.pdf.

Colorado

Dockets: Proceeding No. 17A-0462EG, Decision No. C18-0417 (currently in effect); Proceeding No. 22A-0309EG (proposed for 2024-2027); Proceeding No. 13A-0686EG, Decision No. C14-0731; Proceeding No. 10A-554EG, Decision No. C11-0442; Proceeding No. 07A-0420E, Decision No. C08-0560. Current electric EE savings goals for Xcel Energy establish incremental savings of at least 500 GWh per year starting in 2019, or roughly 1.7 percent of sales.

Black Hills Electric, another regulated utility in Colorado, is in the initial phases of DR deployment.

Background and Framework: In 2007, House Bill 07-1037 directed Colorado electric utilities to pursue cost-effective DSM, incorporated as Colorado Revised Statutes 40-3.2-101, et seq.; HB 17-1227 extends programs and calls for 5 percent energy savings by 2028, compared with 2018.[63] Additionally, C08-0560 (2008) encouraged Xcel Energy to "aggressively pursue all cost-effective DSM" and did not require low-income programs to meet cost-effectiveness requirements. The proceeding adopted nonenergy benefit adders for DSM (and separately for low income programs). Under the 2018 decision, these are now 50 percent (LI) and 20 percent (all other DSM). The Public Service Commission of Colorado (dba Xcel Energy) proposes to continue these nonenergy benefit adder levels in 22A-0309EG.

Colorado has some proposed programs and incentives that are designed within the existing EE/demand-side management plan with rewards for increased energy savings and load flexibility tied to policy goals around carbon emissions. Current incentives have a threshold requirement of 80 percent of net energy savings goal, or 400-gigawatt hours of energy savings. A 2018 the Colorado PUC decision established that a $3 million incentive can be earned in two installments: the first half will be given when 400 GWh of savings (or 80 percent of the goal) is reached, and the second half will be given when the 450 GWh of savings (or 90 percent of the goal) is reached. Total incentives are capped at $18 million.

In 2019, Colorado governor signed Senate Bill 19-236 (and § 40-3-117, C.R.S.), which directed the Colorado PUC to investigate PBR as an alternative regulatory approach for utility oversight. A report was developed by the PUC to investigate whether a transition to the PBR approach would be "net beneficial to the State, in terms of meeting stated objectives of the Commission and other related statutory requirements."[64] The report recommendations concluded that "it is appropriate to continue to build on existing performance-based mechanisms in Colorado, with the immediate focus being on areas that encourage reductions in GHGs."[65]

Latest Developments: Xcel Energy is currently proposing performance-based incentives outside of their rate case, including within their proposed electric resource and clean energy plan.[66] Their proposed DSM and beneficial electrification application for 2024–2027 includes incentives to remove carbon through beneficial electrification, DR, and gas and electric EE with proposed performance targets and incentives. Xcel Energy also proposes an incentive sharing mechanism for DSM that includes an equity-related initiative.

There is an ongoing DSM proceeding for Xcel Energy, requesting a five-part incentive approach with an incentive sharing mechanism that is applicable for both electric and natural gas services. The incentives related to DF proposed by Xcel Energy are included below:

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63 The savings goals for Black Hills Electric are lower.

64 "Performance Based Regulation Report" filed on November 30, 2020, in Proceeding No. 19M-0661EG. https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search.

65 Ibid.

66 More information available in Proceeding No. 21A-0141E. https://coloradonewsline.com/wp-content/uploads/2021/11/21A-0141E_Motion-to-Approve-Settlement-Agreement_FINAL.pdf.

Electric EE Savings: The electric performance incentive is based on a percentage of net benefit created by DSM programs.[67] The incentive offers 40 percent of net economic benefits for all savings above 280 GWh and up to the 550 GWh ceiling, provided that the utility achieves at least 400 GWh in EE savings. Savings over 550 GWh are not eligible for incentive earnings.

DR: The incentive is proposed as outcome-based related to increasing the capacity of DR programs and dispatch capability. The PUC (Xcel Energy) established the following electric DR goals: 2019, 465 MW; 2020, 476 MW; 2021, 489 MW; 2022, 503 MW; and 2023, 520 MW.[68] These demand reduction goals could implicate a variety of DF approaches.

This is a 4-year proceeding, and Xcel Energy is currently operating on a previous framework through 2023 (5-year period). During this time, the framework was established with nonlinear benefits and incentives developed with the intention of encouraging utilities to exceed goals.

Additional Insights: Utility-specific developments include an Xcel Energy proposal for limited beneficial electrification measures that would amount to $1 million, including: (1) heat pump water heaters; (2) dual-fuel air source heat pumps; (3) all-electric new construction; and (4) custom beneficial electrification.[69] This 2021–2022 proposal was subsequently modified with a settlement that expanded on these approaches in 20A-0287EG. The 2022 beneficial electrification proposal (22A-0309EG) introduces more residential and commercial space heating and water heating electrification, with annual budgets starting at $6 million in 2024 and increasing to $17 million in 2027.

67 This mechanism was last modified in the Proceeding No. 10 17A-0462EG ("2017 Strategic Issues") and approved in Decision No. C18-0743.

68 DR or demand reduction goals in Colorado are not required to be coincident with the peak.

69 "NARUC Regulators' Financial Toolbox: Emerging Approaches to Building Electrification in Electric and Gas Utility Efficiency Programs," https://pubs.naruc.org/pub/6BA9D078-1866-DAAC-99FB-86D90B4B3DAE?_gl=1*1dfopzo*_ga*NzQ3OTYxMDM5LjE2NTc1NTE5ODA.*_ga_QLH1N3Q1NF*MTY2NjMwOTM3My4xMDUuMS4xNjY2MzA5OTAxLjAuMC4w.

5. Conclusions

Implementing DF through an effective regulatory framework can lead to lower customer costs, enhanced system stability, and reduced GHG emissions. PBR, combined with AMI and advanced M&V, can advance effective DF models that encourage customers to alter their electricity usage by reducing or shifting consumption. PIMs can encourage utilities to target their performance toward specified objectives whether they are included within a comprehensive PBR framework (e.g., Hawaii) or developed as a supplement to traditional ratemaking practices (e.g., Colorado). Ultimately, performance-based regulatory mechanisms are being designed thoughtfully across the country with consideration of lessons learned from past practices.

The following strategies are based on input from subject matter experts in commissions with PBR frameworks and may be useful for states that wish to implement their own performance-based initiatives.

Strategies for Performance-Based Implementation of Demand Flexibility

1. Examine and potentially introduce a larger number of metrics to assess the effectiveness of various DF mechanisms. Allowing time to collect data across these metrics will allow commissions to better understand the effectiveness of different DF components.

2. Selecting the appropriate metrics may require data and information collection over several years to allow for proper analysis to understand "business as usual" trends. A thorough understanding of the metrics and corresponding data will be a critical input for the development of targets. State commissions in more advanced states of PBR implementation suggest that adjusting the metrics is less challenging than subsequently adjusting the related targets and associated PIMs.

3. Less is more: fewer PIMS can allow for less administrative challenges for the utility and the commission. It is equally important to ensure the PIMs and corresponding incentives are clearly aligned with the ultimate policy goals.

4. Incentives and penalties can be designed with guardrails. Financial incentives with caps/ceilings can prevent excessive financial rewards for utilities that achieve DF-related objectives with more ease than projected. The absence of a maximum dollar amount a utility is allowed to collect for each PIM can lead to a utility focusing on a single, easily achievable objective to maximize revenues, while ignoring others.

5. Establishing an incentive or penalty structure with different tiers—tiered incentives that reward or penalize utilities depending on progress toward specified targets—can create a clear path for utilities that hit various goals over a given timeframe.

6. After each performance cycle, commissions may wish to examine and assess a utility's progress toward achieving a benchmark via a feedback loop.

This research highlights successful elements of performance-based approaches and consideration as more jurisdictions move forward with PBR. Ongoing enhancements and regulatory reform, combined with more robust DF implementation frameworks can facilitate the transition to demand-side resources that are more responsive to the user's needs and can help counter operational challenges related to growing variability on the energy supply side. As regulators and program managers continue to advance PBR frameworks, it will be important to continuously evaluate whether PIMs are creating the intended incentives to advance unrealized demand-side opportunities. NARUC will continue to track state actions and support member utility commissions by creating information sharing opportunities related to the ongoing deployment of demand-side technologies, development of PBR frameworks, and the nexus between the two.

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