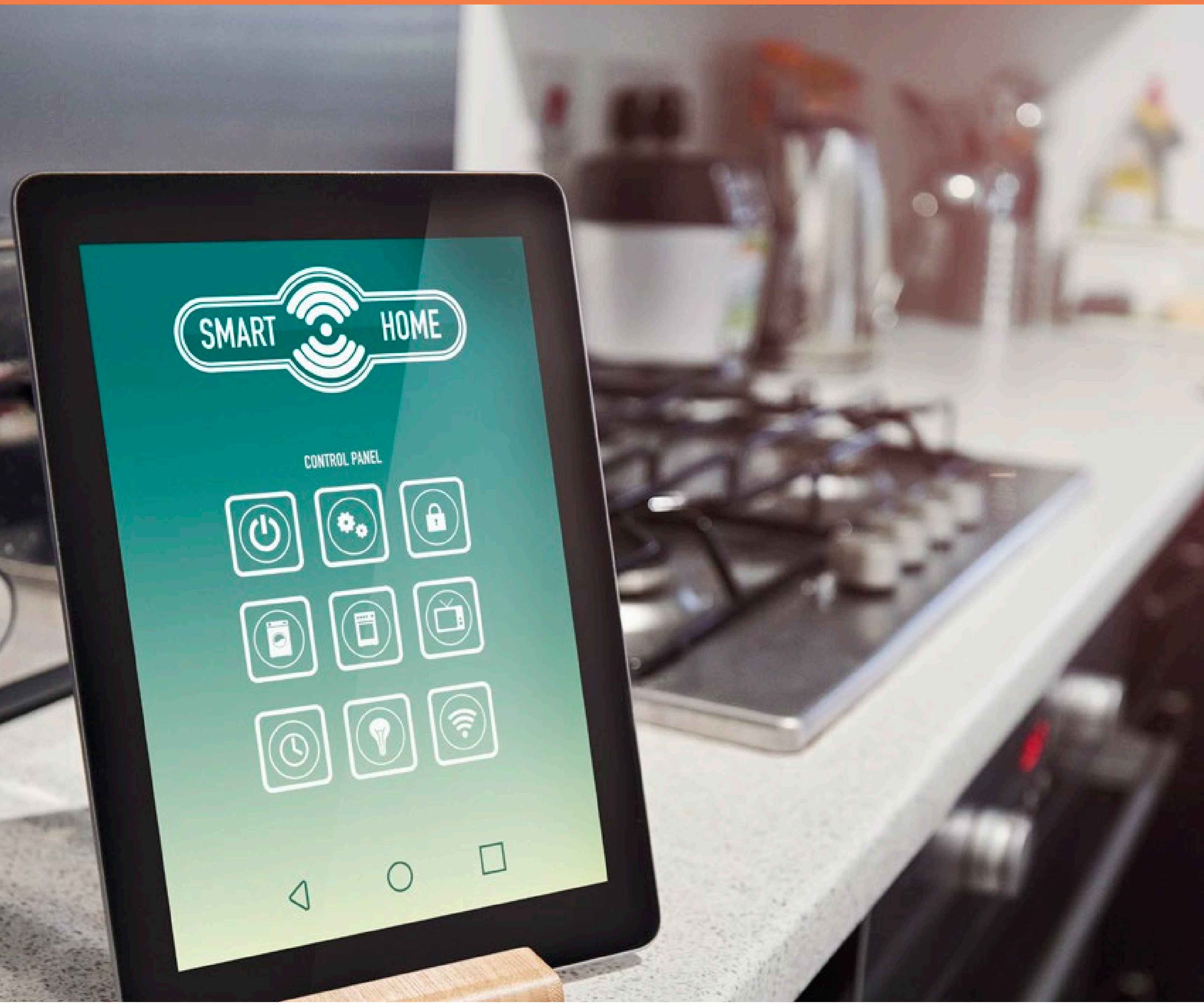

Sparking Grid Savings Starts at Home

Demand Response 2020 Edition

By Lilli Ambort and John Farrell
September 2020

ILSR INSTITUTE FOR Local Self-Reliance

About the Institute for Local Self-Reliance

The Institute for Local Self-Reliance (ILSR) is a national nonprofit research and educational organization founded in 1974. ILSR has a vision of thriving, diverse, equitable communities. To reach this vision, we build local power to fight corporate control. We believe that democracy can only thrive when economic and political power is widely dispersed. Whether it's fighting back against the outsize power of monopolies like Amazon or advocating to keep local renewable energy in the community that produced it, ILSR advocates for solutions that harness the power of citizens and communities. More at **www.ilsr.org**.

About the Authors

Lilli Ambort is an Intern with the Energy Democracy initiative where she contributes to blog posts and interactive features. She is currently studying Global Studies, Political Economy and Environmental Change, with a minor in Chinese Language and Culture at the University of Minnesota, Twin Cities.

John Farrell is co-director of the Institute for Local Self-Reliance and directs the Energy Democracy Initiative. He is widely known as the guru of distributed energy and for his vivid illustrations of the economic and environmental benefits of local ownership of decentralized renewable energy. He hosts the Local Energy Rules podcast, telling powerful stories about local climate action, and frequently discusses the ownership and scale of the energy system on Twitter, **@johnffarrell**. Contact him at **jfarrell@ilsr.org**.

Thanks to Maria McCoy for her throrough review. All errors are our own.

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Related publications from ILSR's Energy Democracy Initiative:

- **Utility Distributed Energy Forecasts**: a report that explains why utilities in Minnesota and other states need to plan for more competition (2020).
- **Reverse Power Flow**: a report that explores how solar + batteries shift electric grid decision making from utilities to customers (2018).
- **Amid EV Surge, Austin Eyes a New Way of Doing Busines**: in this episode of the Local Energy Rules podcast, guest Karl Popham explains how city-owned utility Austin Energy has been a leader in conservation and renewable energy with its electric vehicle and demand response programs (2017).
- **Inclusive Financing**: a report detailing how utilities can knock down major barriers to energy efficiency and renewables by allowing customers to make site-specific investments and recovering utility costs through an opt-in tariff (2016).
- **Beyond Sharing**: a report exploring the opportunity of community renewable energy to enable energy democracy. It examines the benefits and barriers, barrier-busting policies, powerful examples, and how cities and cooperatives can lead the way (2016).

Introduction

At certain moments each year, the grid is strained to capacity by the simultaneous electric use of all customers. These "peak demand" moments drive the design of the entire grid. About **10 percent of national infrastructure investments** are dedicated to serving peak demand, which only occurs one percent of hours each year.

Utility choices impact the disparity between the frequency of peak demand and the costs to serve it. Typically, electric utilities have made major investments in so-called "peaker" power plants that use dirty fuels, and that largely sit idle except in these times of high demand. Expensive to run because they are often idled, utilities recoup the costs through energy sales. In fact, many utilities prefer this model of overbuilding to meet peak demand because their profits rise the more power plants or power lines they construct. Unfortunately for customers, these utilities—often operating with a government-granted monopoly—are too often unchallenged by public regulators despite an abundance of alternatives to expensive, dirty peaker power plants.

Energy efficiency and renewable energy represent two major forces that have changed the economics of meeting peak demand, and new technology has opened the door to better solutions.

Energy efficiency changes the economics of grid planning. It reduces energy use and the cost of the electricity system. It makes it harder to recover the costs of expensive, often-idled power plants when utilities have lower total sales.

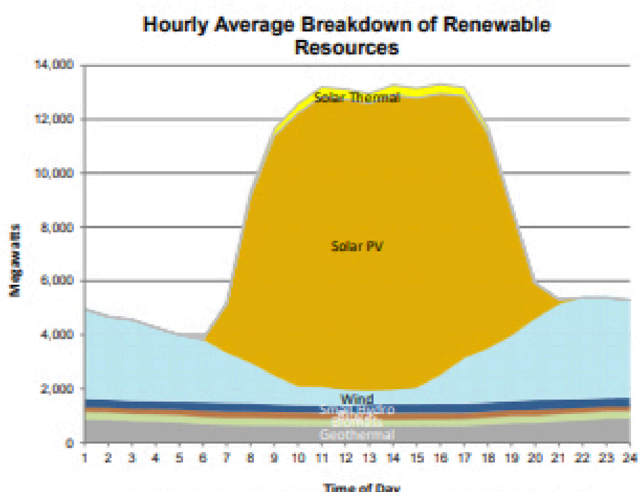
Renewable energy revolutionizes the grid system. Unlike fossil fuel power plants, wind and solar cannot ramp production up or down according to demand but because the energy is produced with zero fuel cost, it's incredibly affordable. With huge amounts of cost-effective wind and solar energy available, it has become much less costly for grid operators to ask customers to shift their energy use to this period of relative abundance than to build energy storage (for now) or fossil fuel backups. The chart below, from the **California ISO**, illustrates the need and opportunity for flexibility within the California electricity grid, with abundant daytime solar energy resources.

24-Hour Renewables Production

Renewable Resources	Peak Production Time	Peak Production (MW)	Daily Production (MWh)
Solar Thermal	10:24	375	3,737
Solar	13:25	11,038	115,290
Wind	21:17	3,713	49,738
Small Hydro	19:08	389	7,810
Biogas	4:16	199	4,696
Biomass	7:12	317	6,945
Geothermal	23:58	884	16,815
Total Renewables			**205,031**

Total 24-Hour System Demand (MWh): *693,533*

This table gives numeric values related to the production from the various types of renewable resources for the reporting day. All values are hourly average unless otherwise stated. Peak Production is an average over one minute. The total renewable production in megawatt-hours is compared to the total energy demand for the ISO system for the day.



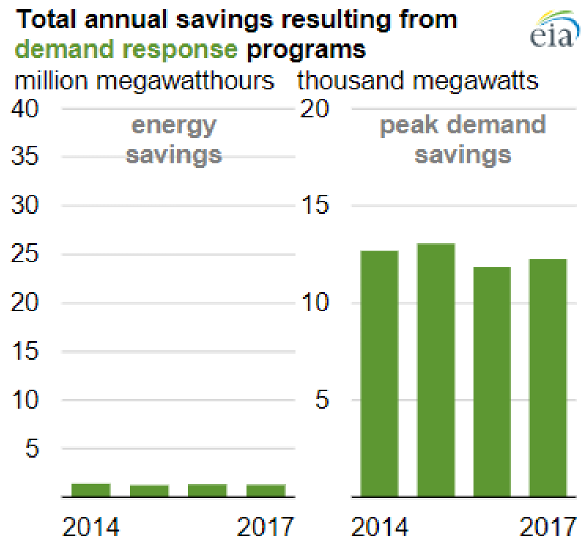
This graph shows the production of various types of renewable generation across the day.

System Peak Demand (MW) *one minute average	**36,732**
Time:	**18:31**

Together, energy efficiency and renewable energy make flexibility a much more cost-effective approach to peak demand than expensive power plants.

Flexibility is not a new concept. Utilities have had limited "demand response" programs, which ask customers to flex their energy use, for years. Most common are air conditioning programs, in which customers allow the utility to cycle off their air conditioner for a fraction of each hour using a radio control. In aggregate, these programs can reduce total demand in a way that customers barely notice. Some other demand response programs are more traditionally focused on commercial and industrial customers, who agree to cycle down energy use for a financial incentive. Other programs, such as those run by third parties like OhmConnect, target residential users. In a recent **survey of utilities** by the Smart Electric Power Alliance, 50 percent of utilities responded that they were interested in implementing demand response programs, 20 percent are currently planning to implement demand response programs, and just 5 percent have implemented programs.

These few, existing demand response programs provide significant energy and financial savings for the utility and customers. In 2018, over **400 programs** (often more than one per participating utility) provided 1.4 million MWh in energy savings and $1.1 billion in customer incentives. They reduced peak demand by nearly 12 gigawatts, the equivalent of two dozen nuclear power generators.



Existing programs have only scratched the surface. New technology enables more flexibility and responsiveness, from smart meters to smart thermostats. These tools allow the utility to price energy based on the time of use and its actual cost, offering customers an incentive to use power when it costs less to deliver and giving the utility more control over energy use. Smart technology, such as smart plugs and thermostats, require no additional infrastructure. Set up can be as easy as plugging the new smart plug into the wall and connecting it with your home internet, although smart thermostats require a bit more complicated installation. Smart technologies such as these are affordable to most and are becoming widely used in households across the United States.

Third party aggregators and smart technology entering the market can expand the reach of utility demand response programs, especially in the residential sector. Third-party aggregators refer to non-utilities that can group customers together. For example, the demand response potential of multiple residential customers can be managed as an aggregate and provide several megawatts of demand response capacity. Third party aggregators take advantage of smart technology by connecting with homeowners through apps, automatically shutting off devices connected to smart plugs and turning off heating/cooling devices controlled through smart thermostats.

There is an unprecedented opportunity to move beyond air conditioners and tap the many other sources of controllable electricity demand in homes and businesses, and to reduce costly utility investments in peaker power plants. This report touches on both Commercial and Industrial (C&I) and Residential demand response, but primarily focuses on the opportunity to expand programs for residential customers.

Utility Financial Incentives and Regulations

Demand response programs have lagged behind their technical and economic opportunity largely because, with the current rules, utilities make less money using them. In most states, utilities operate as monopolies that own every part of the grid: from the power plant, to the power lines, to the electric meter on the home or business. Without competition, these utilities make a profit when they invest their money in new infrastructure, as long as regulators approve their investment. In other words, they profit by building things. When it comes to meeting peak demand, building power plants makes money. Shifting customer demand, and avoiding demand peaks altogether, typically does not. So, utilities shirk demand response in favor of building things to make a profit. Even not-for-profit utilities, such as cooperatives and municipal utilities, tend to be reluctant to implement demand response.

States have three options to motivate utilities: mandates, incentives, and savings-sharing.

Where states have given utilities a monopoly and the incentive to build, public commissions can require utilities to do things in the public interest. Even though demand response programs can save customers money, few regulators have ordered their use. Additionally, if the orders come without penalties, utilities have little motivation to increase participation rates or to make demand response programs cost effective and widely accessible.

In some states, regulators aim to overcome the utility's bias toward power plants by providing **financial incentives** when utilities achieve demand response goals. Utilities can receive a bonus to their rate of return on investments or a share of the cost savings from demand response. State commissions must approve the target level and work with the utility to determine the incentive rate and funding. In Connecticut, the **Conservation & Load Management (C&LM) program** is funded by a charge on customers' electric bills that is collected by the state. If utilities achieve at least 70 percent of their demand response implementation goal, they can receive incentives ranging from 1 to 8 percent of program expenditures.

Utilities can also **share in a portion of the energy savings** from demand response. The savings are the avoided costs of additional supply-side resources subtracted from the demand response program costs (e.g. the cost of a new power plant minus the cost of using demand response to get the same energy). Shared energy savings incentivizes utilities to promote cost-effective demand response programs and encourages careful cost management to make programs widely available. Utilities will typically receive an increasing percentage of shared savings with increasing participation rates and cost effectiveness.

Table 1: Northern States Power 2007 Electric Incentive Calculation

Electric	Kilowatt-Hour	Percent of Base	Estimated Benefits Achieved	Estimated Incentive
90% of goal	198,574,585	0.00%	150,383,459	0
100% of goal	220,638,428	0.8408%	167,092,732	1,404,916
110% of goal	242,702,270	1.6816%	183,802,005	3,090,815
120% of goal	264,766,113	2.5224%	200,511,278	5,057,697
130% of goal	286,829,956	3.3632%	217,220,552	7,305,562
140% of goal	308,893,799	4.2040%	233,929,825	9,834,410
150% of goal	330,957,641	5.0448%	250,639,098	12,644,241

Source: Xcel Energy, 2006.

In Minnesota, cost-effective demand response allows for shared savings between utilities and customers — as long as the utility also meets part of their target, as seen in the **chart above**. The utility has to achieve more than 90 percent of its goal before it begins to receive any incentive. As the utility achieves a greater percentage of its goal for customer energy savings, the utility receives a greater share of those savings. Shared savings is an incentive mechanism designed to ensure cost effective demand response. Without net benefits to customers, the utility does not receive a reward.

Falling Short of the Potential

The Federal Energy Regulatory Commission finds that **less than 5% of U.S. households** are participating in programs to reduce demand at opportune times, despite residential customers using more energy and causing more peak energy demand than non-residential users. Commercial and Industrial customers make up more than **10.9 GW of enrolled demand response capacity**, while the residential/mass market customers only make up 5.6 GW.

Utilities have a strong incentive to focus on commercial and industrial demand response because economies of scale can be obtained faster and with greater ease. In the past, business-oriented demand response programs also tended to be more cost-effective per kilowatt saved than residential programs, in part because larger businesses may have dedicated staff focused on reducing energy costs.

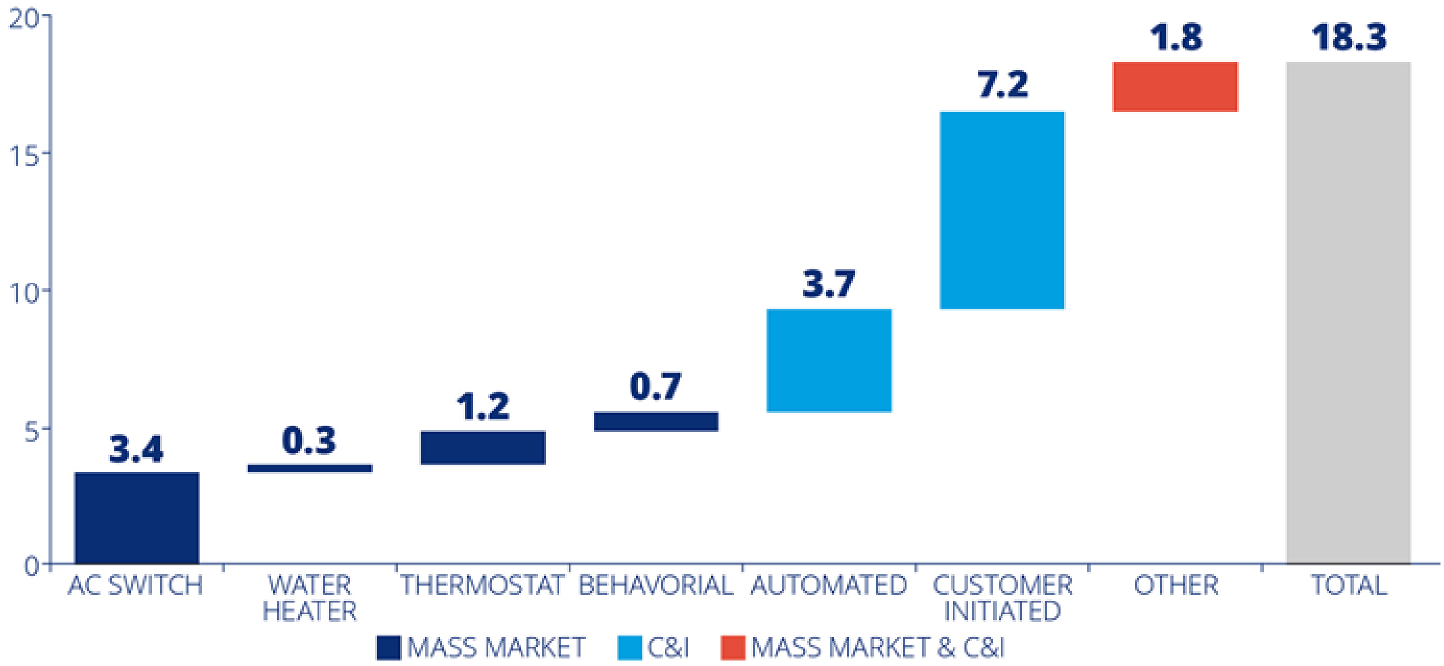
A **study done in California** shows that the top barriers to demand response are (in order):

- Limited advanced metering infrastructure penetration
- Ineffective program design
- Low consumer interest
- Lack of options
- Fear of a lack of cost recovery
- Fear of customer backlash

Not surprisingly, limited communication technology ranked number one. Without meters (or other devices) that can measure and/or price electricity based on the time of use, utilities can't easily reward helpful consumer behavior. The second and third most significant barriers, ineffective program design and low consumer interest, go hand in hand — more effective program design increases consumer interest. Residential demand response is also more difficult to implement because it relies on **recruiting small energy users** to enroll in the program.

The following chart illustrates several variations on the theme of underutilized residential demand response: 1) commercial and industrial customers currently provide much more demand response capacity, 2) legacy air conditioning programs still dominate residential demand response programs, and 3) there's very little utilities have done with automated or smart demand response in the residential space, other than thermostats.

2017 ENROLLED DEMAND RESPONSE CAPACITY BY PROGRAM TYPE (GW)



Source: Smart Electric Power Alliance, 2018. N=155. (Note: This figure represents total capacity collected in SEPA's Annual Utility Survey in 2018. Results are based on responses from 155 utilities. See Methodology for more details.)

The chart also overstates the impact because it displays *enrolled* capacity, but actual **dispatched capacity** has only been 10.7 GW. The gap illustrates how utility programs could do much more to tap residential demand and could potentially improve participation with smarter technology.

Residential demand response could be particularly important in certain regions. According to the U.S. EIA, residential energy use in Texas alone can account for up to **67 billion kW hours** (over 60%) of peak load versus the 18 billion kilowatt hours used by the commercial and industrial sector.

Poor leverage of new technologies by utility demand response programs limits residential demand response potential even further. **Direct load control (DLC) programs** with control over AC switches, electric heating, and water heaters have been used by utilities for decades. Direct load control allows the utility to use simple, one-way controls to reduce peak load when energy supply is limited. However, the technology does not provide feedback from the customer, leaving the utility with two problems. First, without knowing if a customer's air conditioner or other device is running, it won't know if sending an "off" signal will reduce energy use. Second, it can't accurately attribute energy savings to particular customers, because it doesn't know which ones are reducing their use at peak.

Given the potential to shrink the disproportionate cost of meeting peak demand with power plant capacity, regulators should increase focus on cost-effective residential demand response opportunities. There are plenty of options.

The good news is that successful demand response programs don't require advanced or smart meters, which have yet to replace older meters for **50% to 75% of customers across the country**. Energate, one of many companies in the "connected home" space, offers smart devices to consumers and utilities that simply pair with an Internet connection — **no smart meter required**. That could be a significant tool in cities like Minneapolis, where, like many other large cities, **over 90% of households** have access to a wired, broadband Internet connection.

Potential Residential Savings

Demand response programs fall under **two categories**: "price options" and "incentive or event-based options." Price options align what customers pay with what electricity costs to produce, either penalizing use during peak periods or rewarding shifts to lower cost periods, or both. Event-based options focus on controlling load at specific peak demand moments. The two most common options available to residential customers are time-of-use (TOU) pricing and direct load control (event-based), but the opportunities are changing.

Table 2: Common Types of Demand Response Programs

Price Options	Incentive- or Event-Based Options
TOU rates: Rates with fixed price blocks that differ by time of day.	**Direct load control**: Customers receive incentive payments for allowing the utility a degree of control over certain equipment.
CPP: Rates that include a pre-specified, extra-high rate that is triggered by the utility and is in effect for a limited number of hours.	**Demand bidding/buyback programs**: Customers offer bids to curtail load when wholesale market prices are high.
RTP: Rates that vary continually (typically hourly) in response to wholesale market prices.	**Emergency demand response programs**: Customers receive incentive payments for load reductions when needed to ensure reliability.
	Capacity market programs: Customers receive incentive payments for providing load reductions as substitutes for system capacity.
	Interruptible/curtailable: Customers receive a discounted rate for agreeing to reduce load on request.
	Ancillary services market programs: Customers receive payments from a grid operator for committing to curtail load when needed to support operation of the electric grid (i.e., ancillary services).

Source: U.S. EPA National Action Plan for Energy Efficiency, 2010.

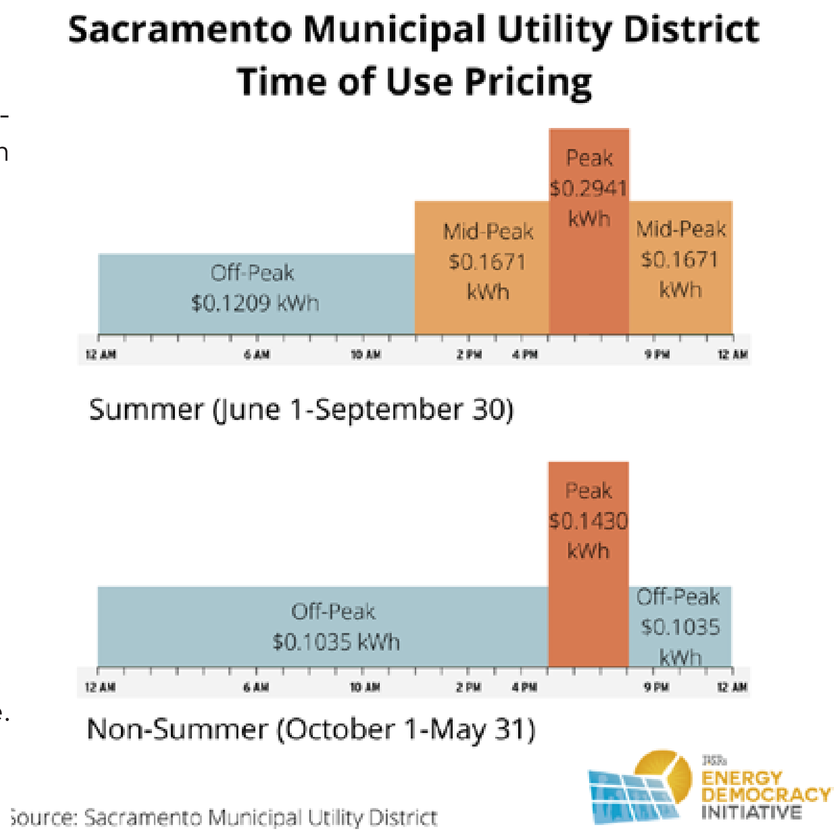
Advances in smart home technology are quickly entering the residential sector. Customers empowered with smartphones, smart apps, and smart devices have the ability to adjust their energy use in response to the electricity system's needs. A variety of smart thermostats can be controlled from smartphones, for example. Customers can restrict when they run appliances, or charge electric vehicles, to times with low power costs. In some markets, companies can aggregate these empowered customers to lower overall energy demand significantly using "automated demand response." As more homes install smart thermostats and smart plugs, potential demand response in the residential sector drastically increases. **Minnesota residential customers** for example, have access to smart plugs, smart thermostats, and heating and air conditioning direct load control programs, similar to programs offered through PG&E and demand response aggregators in California. Smart technology can be used to decrease energy use during peak demand events or to decrease energy during peak pricing.

Customers have a growing capability to address peak demand, but they need an incentive to act. Regulators and utilities must provide customers with pricing options or event-based options customers can use to both reduce their costs and the electricity system's costs.

Pricing Options

The first category of demand response programs includes pricing options, such as **time-variable pricing.** The most common are time-of-use (TOU) rates, where electricity rates differ based on time blocks throughout the day. These time blocks typically include higher prices for electricity during afternoon peak hours and lower prices during overnight off-peak hours. Time-variable pricing aims to align the cost of providing electricity with the cost of using it, financially incentivizing customers to reduce energy use at peak times.

Nationwide potential for load flexibility (another term for demand response) could total **200 Gigawatts by 2030**, , with the most cost-effective potential lying in dynamic pricing. So far, utilities fall short of tapping the full potential. About **52 percent** of all residential electric meters are advanced meters that can monitor the performance of direct load control and allow for time-of-use demand response programs. However, only **14 percent** of utilities in the United States offer time-of-use rates, with 2.2 million customers, or 1.7 percent of all residential customers, enrolled in TOU rates. Although nearly half of investor-owned utilities (IOUs) offer time-varying pricing, most have enrollment rates of less than 1 percent in their TOU programs. **Barriers include** poor experience with early pilots, challenges with customer education, and identifying the right price differentials between peak- and off-peak pricing.



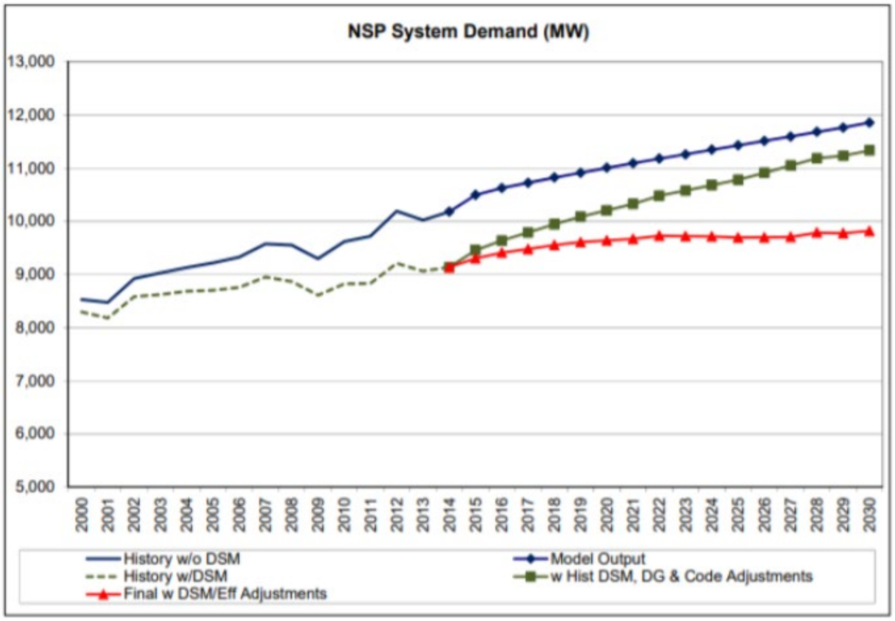
The **Sacramento Municipal Utility District** (SMUD) performed pilot testing of time-of-use rates from 2011 to 2013. SMUD offered three time-of-use pricing plans targeting a shift in their summer peak demand of **400 MW**. The utility was able to shift 8 to 10 percent of peak load outside of the 4 p.m. to 7 p.m time range. Roughly 6,000 customers remain enrolled in the utility's TOU program after the end of the pilot.

Incentive or Event-Based Options

Incentive or event-based demand response programs are invoked by certain conditions that put the grid under stress. Grid congestion, local or system temperature, system economics, and more can trigger a demand response event. Incentive or event-based options include direct load control, behavioral programs, smart technology and third party aggregation.

DIRECT LOAD CONTROL PROGRAMS

The first and most common form of incentive or event-based demand response are direct load control programs. Direct load control has been around for decades and is the most common demand response program. Direct load control programs are operated either by a utility or third party aggregator and use remotely controllable switches that can turn on or off power to an appliance. About **3.7 Gigawatts** (20 percent) of enrolled demand response capacity is direct load control.



The largest utility in Minnesota, Xcel Energy, offers a handful of programs to commercial and residential customers to reduce energy use from air conditioning systems. Dominated by heating and air conditioning direct load control programs (particularly the Saver's Switch program), **Xcel's demand response program** is one of the largest in the Midwest (shown **at right**). Currently, its demand response programs have 824 Megawatts (MW) of registered, controllable customer load, with orders from regulators to add an additional 400 MW by 2023. However, the potential for demand response savings is much greater than what Xcel's programs offer. Direct load control and advanced metering infrastructure still has a lot of potential to decrease peak energy use, but is less effective in residential settings without additional and more flexible programming. With the added flexibility of smart home technology entering even more homes than direct load control and advanced metering, utilities can diversify their demand response programs further.

BEHAVIORAL DEMAND RESPONSE PROGRAMS

Behavioral demand response programs also fall under the incentive-based category. Possible with or without smart meters, these programs aim to change customer behavior by tying an incentive to useful behavior.

For example, Minnesota Valley Electric Cooperative's **Energy Wise** demand response program has automated and manual components. Customers can form teams to collectively reduce electricity use when the utility sends out messages on social media, by text, and other means. The highest-performing teams can win gift cards and prizes, and are notified of peak energy events via email, text, or phone the day prior. Customers can use automated, smart devices to reduce energy use during the peak period or can simply turn off lights and appliances during the designated time.

In a similar vein, Baltimore Gas and Electric rolled out its behavioral focused demand response program **SmartEnergy Rewards** in 2012 to call on customers to reduce peak demand. The program gives customers rebates on their electricity bills for reducing their energy use during peak demand events, known as Energy Savings Days. As of 2017, SmartEnergy Rewards is the largest dynamic pricing program in the nation. Residential customers with smart meters are automatically enrolled in the program. Those without smart meters can participate as well, instead being notified by phone, email, or text the day before an Energy Savings Day. In 2017, there was a 74 percent program participation rate, $6.1 million was paid to customers in bill credits, and 330 MW of peak demand was saved.

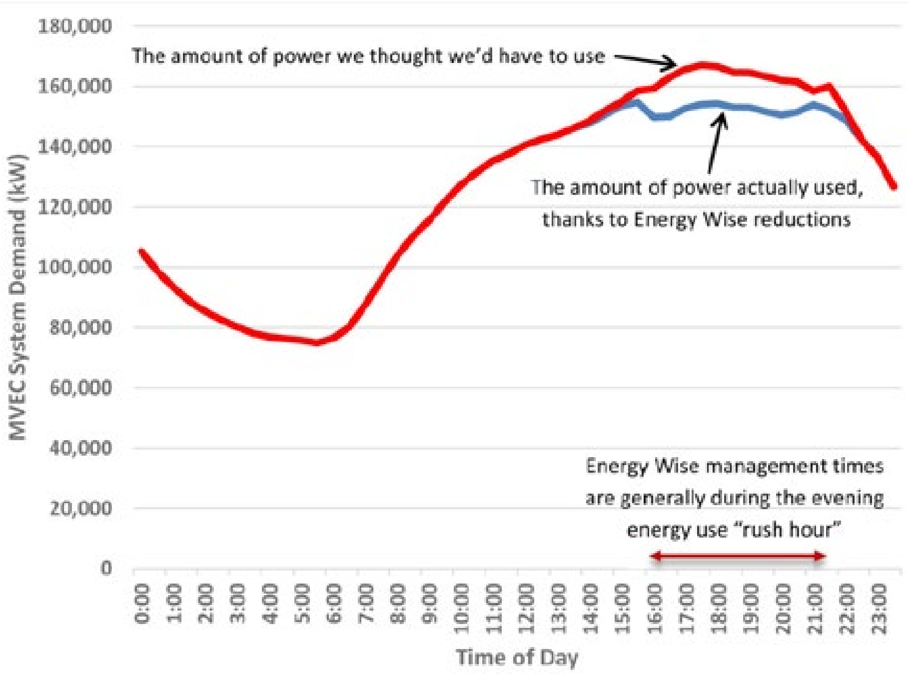
Behavioral demand response programs are effective for homeowners without smart meters that still want to participate in reducing peak load. The development of smart technology makes participation easier, because homeowners can connect their smart plugs to their devices or install a smart thermostat to automatically participate in demand response events.

SMART TECHNOLOGY

Smart technology offers homeowners an alternative to reliance on utility advanced meters. Broadly, smart devices allow customers to remotely manage (via an app), schedule, or connect for third-party management devices to control their electric appliances. For example, this includes a smart plug where a customer could cycle off a window air conditioner with a phone app, or a smart thermostat that can be controlled by a utility or third party. Demand response programs enabled through smart technology can automatically reduce residential energy use without homeowners ever having to lift a finger.

Given the slow adoption of smart meters, smart technology for thermostats and plugs are becoming a more plausible alternative that does not require new infrastructure. Currently, **1.4 million electric customers** have smart thermostats, accounting for 1.2 GW of enrolled demand response capacity in 2018.

Minnesota Valley Electric Cooperative's Energy Wise program provides a free smart thermostat that can automatically control cooling and heating during peak energy events. The 44 percent of customers who participate receive a 10 percent discount on electricity during summer months. In exchange, the utility pre-cools the house by two degrees in the morning and allows temperatures to rise by up to 4 degrees five to seven times per month. Minnesota Valley Electric Cooperative's demand response programs, smart thermostats and beyond, have reduced peak demand by **31 percent**.

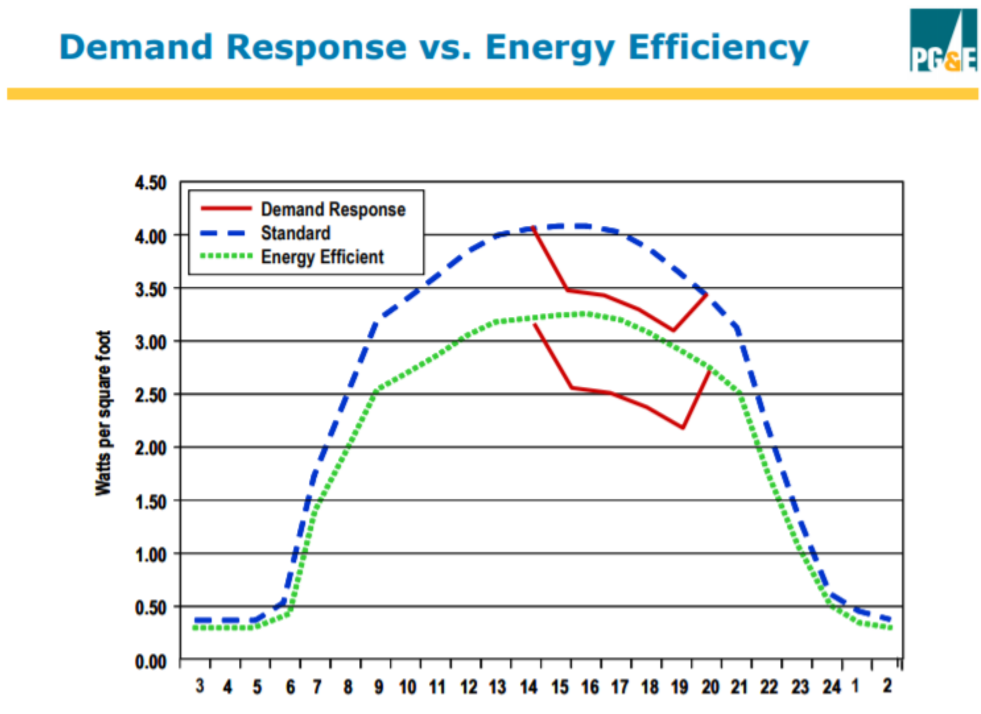


One barrier to broader adoption of smart technology is home internet access. Only **56 percent** of lower-income households with yearly incomes of less than $30,000 have access to home broadband. Most low-income households rely on cellular devices for internet access. Without reliable internet access for most low-income Americans, smart technology may not be feasible. Even with reliable internet access, U.S. households with an income of less than $50,000 a year are **the least likely to** to own smart energy solutions. The associated costs of smart technology are too much for most low-income households to buy into. Programs like the Department of Energy's **Weatherization Assistance Program**, which helps low-income families increase the energy efficiency of their homes, may be necessary to increase smart technology adoption among low-income households.

Aggregation

The latest opportunity for demand response programs is to allow third party aggregators to expand demand response where utility programs haven't. By setting goals for demand reduction and allowing non-utility businesses to group customers together to reduce demand, utilities can invest in demand response without having to develop specific programs, vet technologies, or learn new marketing skills.

PG&E's Capacity Bidding Program in particular is unique, as it allows third party demand aggregators to compete for the reduction of residential peak energy use. These providers rely on smart technology to automatically reduce energy use by participating residential customers. They also use app notifications and text messages to encourage users without smart technology to reduce their energy use on their own. The number of third-party demand response providers registered with the California Public Utilities Commission alone has **tripled since 2016**. The chart below demonstrates the reduction in energy use per square foot during peak demand times through PG&E's demand response programs, including third party aggregation.



Source: Public Interest Energy Research (PIER) Demand Response Research Center

Residential and small commercial customers **make up over half** of PG&E's peak demand. PG&E's demand response programs, including third party aggregators and the utility's other programs, collectively provide over 525 MW of load reduction.

Another successful third party aggregation partnership has been between PG&E and OhmConnect. Currently, OhmConnect serves in partnership with utilities in California, those served by Toronto Hydro in Ontario, and some Texas Smart Meter users. The program saves **745 MWh per year** at peak times, across all its customers.

OhmConnect targets residential customers only and has an option to integrate smart devices to allow for customer-initiated or automated savings. When an "**OhmHour occurs**" occurs (once or twice per week for an hour), customers can turn off their lights, heating, cooling, etc. to save energy. If their account is connected to their smart thermostat or smart plugs, then customers can participate in AutoOhms, where the app can communicate with the devices to shut down automatically. **AutoOhms** are typically shorter, on average lasting 15 minutes, but no longer than 45 minutes, and happen more frequently throughout the week. OhmConnect uses the meter data from the utility to determine whether you used less energy, and if you did, you earn points based on how much energy you saved. OhmConnect users with smart technology save more than twice as much as those who manually turn their devices off. Program participants save **100 to 200 kWh at peak times per year**, per household and earn between $100 to $300 per year.

Other **residential aggregators** such as Autogrid, Chai Energy, EnergyHub, Uplight, and Sunrun have all recently registered in California, but not all states allow aggregation. For example, Minnesota has **opted out** of retail demand response participation and does not allow third party aggregators. FERC Order 745 establishes standards for demand response aggregator competition in regional transmission markets, but Order 719 gives states the option to "opt-out" of retail demand response.

As smart technology, third party aggregators, and behavioral demand response programs are thrown into the mix, demand response programs become more flexible and widely available to residential customers looking to save energy and money.

Conclusion

Homes and businesses represent a large source of manageable energy consumption. Decades-old utility programs enable control of a few major sources of residential or commercial energy use, but much untapped potential remains. Residential demand response is ready to bring greater energy savings to consumers. Utilities and third party demand response aggregators are beginning to explore how smart home technology can bring grid flexibility, while rewarding residential customers.

Utilities can use commercially available smart technology to allow themselves or their customers to reduce peak energy consumption. Transparent pricing based on the actual costs of electricity motivates customers to shift the time they use manual appliances such as washers and dishwashers, further reducing peak energy demand.

As residential demand response matures, utilities and demand response aggregators should get ready to expand the market.. The potential for this abundant, low-cost source of peak energy supply should be hard for utilities, and their regulators, to ignore.