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DELIVERING ON THE PROMISE OF CALIFORNIA'S DEMAND RESPONSE PROGRAMS

An Opportunity for the State to Maximize the Flexibility and Efficiency of Its Electrical Grid

California's energy landscape is more complex and dynamic than ever. Energy regulators face renewed challenges on how to meet the state's energy needs in cost-effective and environmentally friendly ways. One promising tool is "demand response," which attempts to exert control over the demand for energy to more efficiently balance energy demand and supply.

California has an extensive history with demand response programs, which were well-received by energy customers as early as the 1990s. But the programs were not triggered often by utilities before 2000, and they were considered more of an insurance policy. The importance of demand response programs in California's energy policy increased in 2003, when the state's loading order (the order in which types of energy resources are used) was established by the California Energy Commission (CEC), the California Public Utilities Commission (CPUC), and the California Consumer Power and Conservation Financing Authority. According to the CEC, demand response was placed at the top of the loading order, along with energy efficiency, as a preferred resource to avoid traditional or nonrenewable energy generation.

Will Demand Response Programs Help Meet California's Energy Needs?
The state's energy regulators are creating demand response programs that can act as supply-side resources to reduce or increase energy demand at a particular time and location and by a specific amount. The more control utilities and the California Independent System Operator (CAISO) have over energy demand, the more likely they will meet California's overall energy needs with fewer power plants and less costly electricity.

In 2003 the CPUC set the goal of meeting 5 percent of the system's annual peak-energy demand through demand response programs by 2007. This goal was applied to "nonemergency" demand response programs (non-interruptible programs), and as of spring 2014, California was slightly more than halfway toward meeting that 2007 goal. (Although if "emergency" demand response programs—such as the Base Interruptible Program and the Agricultural and Pumping Interruptible Program—are included in the count, the 5 percent goal was met in 2011.)

The Benefits of Demand Response

The CPUC defines demand response as follows: "Changes in electricity use by customers from their normal consumption pattern in response to changes in the price of electricity, financial incentives to reduce consumption, changes in wholesale market prices, or changes in grid conditions." The California Independent System Operator (CAISO), which is tasked with dispatching power to ensure the grid's reliability, believes the key to demand response is when energy customers respond to a signal (such as an e-mail, text message, telephone call, or thermostat signal) correlated to the state's current electrical grid conditions.

In the CEC's 2013 Integrated Energy Policy Report, the commission states the benefits of demand response programs include:

- a more efficient electrical system with lower overall system costs;
- a reduced need for new power plants and transmission infrastructure;
- more control by energy customers over their electric bills.

The CEC also says demand response can assist in integrating renewable energy to meet California's 33 percent Renewables Portfolio Standard requirement—and potentially integrate even higher levels of renewables.

However, the CEC, CAISO, and CPUC are concerned demand response is not displacing traditional resources and not reflecting its place at the top of the loading order. In addition, it is questionable whether demand response can integrate renewable power if it cannot allow for both the upward and downward adjustment of power.

Improvements Are Needed

In the 2014 Energy and Environmental Economics, Inc., study, "Investigating a Higher Renewables Portfolio Standard in California," overgeneration of energy is identified as the largest renewable-integration problem for a higher renewable-energy portfolio standard in California. The study asserts that demand response could reduce the impacts of overgeneration and ramping (when a sharp increase or decrease in, for example, wind speed causes a large rise or fall in the amount of power generated), but advances in demand response are needed to allow for upward and downward adjustments.

There have been few pilot programs demonstrating the use of demand response to address overgeneration of power; however, one pilot program demonstrated success in using demand response to respond to a utility signal to increase energy demand to improve wind-power integration.[1] This program was conducted by the Bonneville Power Administration, a federal agency that markets wholesale electrical power from numerous hydroelectric dams on the Columbia River and other energy resources to parts of California, Idaho, Montana, Nevada, Oregon, Utah, Washington, and Wyoming. Within those eight states, the Bonneville Power Administration provides electricity to 142 utilities, most of which are municipal utilities, co-ops, and public power districts.

In 2012, CPUC staff studied the demand response programs for Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E) and found that they "underutilized demand response programs and dispatched their power plants to meet peak demand far more frequently in comparison to demand response programs. The demand response programs were not utilized to their full Resource Adequacy[2] capacity, even during extremely hot weather conditions."[3] CAISO also has not been turning to utilities' demand response programs as a resource to meet real-time grid needs, except as a last resort.

California utilities spend significant amounts of ratepayer funds on the state's demand response programs, yet the benefits to ratepayers are unclear. The potential for a utility to reduce energy demands by triggering a demand response program does not result in ratepayer benefits if the energy reductions do not actually avoid ratepayers' generation costs.

California's demand response programs should clearly demonstrate the degree to which they:

- avoid use of higher-cost energy generation;
- avoid construction of traditional power plants or transmission infrastructure;
- improve integration of renewable power;
- lower energy costs for consumers.

Currently, the CEC, CAISO, and CPUC are reviewing California's demand response programs and organizing them into two categories: supply-side resources (programs that reduce or increase energy demand at a particular time and location and by a specific amount) and load-modifying programs (programs that modify the energy load shape through customers' behavioral changes that result in improved electrical grid function).

The agencies believe each program must act consistently as either a load-modifying program or a supply-side resource to accomplish displacing traditional energy generation or integrating renewable power, and their categorization project is expected to be completed in 2014.

Demand Response in the United States

Avoiding peak energy demands offers the nation significant cost savings. According to the Demand Response and Smart Grid Coalition, 100 hours of peak-demand usage nationwide accounts for 10 to 20 percent of the nation's cost of electricity every year. Many other Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) across the country have recognized the benefits of meeting peak demand through demand response programs.

In 2012, CAISO had 2,430 megawatts in demand response resource potential—the fourth most of any ISO and RTO in the country. Grid operators PJM Interconnection, Midcontinent Independent System Operator, and ISO New England all had more megawatts and a larger percentage of peak-demand resource potential than California (see

Appendix A, "U.S. Demand-Response Resource Potential at Independent System Operators and Regional Transmission Organizations," on page 13). "Overall, the demand response resources' potential contribution in U.S. RTO/ISO markets has increased by 4.1 percent since 2009," says the Federal Energy Regulatory Commission. From 2011 to 2012, demand-response resource potential fell nationwide, but increased slightly in California.

Demand response has significant potential for the country. The Energy Research Council found that while 28 percent of middle-market companies expressed great interest in demand response programs, only 9 percent were taking advantage of one. The council also found that larger companies were much more likely than smaller companies to participate in demand response programs, primarily because of a lack of awareness and a lack of education about program benefits.

Demand response is implemented differently throughout the country; some programs are offered through wholesale competitive energy markets, while others come through retail contracts with utilities. PJM Interconnection has more megawatts of demand response than other RTOs or ISOs; it operates the wholesale energy market and manages the grid for 51 million people, covering a service territory that includes 13 states (all of some states, and portions of other states) and the District of Columbia. The company categorizes its demand response programs into two broad classifications: emergency and economic.

Emergency Demand Response is treated like a conventional energy generator; its residential, commercial, and industrial participants are allowed to bid in the wholesale market the same way participants bid on any other energy resource, and they are expected to perform like other resources.

Economic Demand Response is used to displace generation and provide ancillary services; energy customers who use it are expected to perform and respond within certain time frames, depending on the program's options. "Economic Demand Response primarily represents a voluntary commitment to reduce load in the energy market when the wholesale price is higher than our published monthly PJM net benefits price," according to PJM Interconnection.

The Federal Energy Regulatory Commission recently approved PJM Interconnection's request to alter its tariffs to increase its ability to use demand response throughout the year by allowing incentives to provide for demand response in the winter. For example, extreme cold weather on the East Coast has expanded the need for peak demand beyond just the summer months.

PJM experienced a dramatic decline in demand response use due to the tightening of its rules on participation, increased data collection, and lowered prices in the wholesale marketplace. For instance, its demand response resource potential dropped from a 14,127-megawatt reduction in 2011 to a 10,825-megawatt reduction in 2012; that drop exceeded California's total demand response potential for 2012.

Diesel backup power is used more heavily in demand response programs outside of California. Diesel generators allow demand response program participants to continue using power during events by shifting their energy load to diesel generators. However, using diesel generators impacts the air quality, and the U.S. Environmental Protection Agency currently is considering changes to demand response rules.

"Backup diesel generators now provide an estimated 10 to 20 percent of the roughly 10,000 [megawatts] of demand response that is in service on the PJM Interconnection, a section of the U.S. power grid spanning 13 states, from Illinois to the Atlantic Ocean," wrote Gabriel Nelson, a reporter for the Environment and Energy Publishing Web site, in July 2012.

In ISO New England territory (which covers Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont), the Federal Energy Regulatory Commission fined two companies, including Rumford Paper, and energy manager Richard Silkman for market manipulation by creating "phantom load reductions" to increase their demand response payments. One of the companies and Silkman claimed there was no specific rule prohibiting the action of artificially inflating baseline energy consumption to give the appearance that a company had reduced loads from normal operations when it actually did not reduce loads.

In the recent enforcement action against Rumford Paper, the Federal Energy Regulatory Commission discovered the company normally used an internal generator to supply some of its own power; however, when ISO New England was establishing its demand response baseline, it curtailed its own generators to establish an artificially inflated baseline so the company could later claim load reductions without reducing its load from normal operations.[4] Thus far, these incidents of fraud are rare, but they underscore the challenges of determining real demand reductions.

The New York Independent System Operator also saw a decline in its demand response program after changing market rules "to enhance estimates of providers' ability to deliver demand response during peak conditions."[5] In addition, the New York Independent System Operator stated that "increased use of demand response resources may also test the ability—and willingness—of some program participants to sustain their commitments."

Even in areas of the country with more demand response resource potential than California, how to ensure deliverability of savings at a specific time, for a specific amount, and in a specific location are issues still to be resolved. (In fact, California is more stringent in some areas, such as diesel backup generation.)

In 2011 the CPUC adopted a decision prohibiting Resource Adequacy program credit for demand response programs that use fossil-fuel backup generators. As other states change rules and require more data about performance and other factors, participation has declined. The balance of maintaining or enhancing performance and ensuring cost-effectiveness while increasing deployment is a difficult challenge for the entire country. Despite these challenges, demand response continues to offer potentially significant benefits to the U.S. grid.

Demand Response in California

California spends significant resources on demand response, yet how beneficial it has been is unclear. The CPUC approves ratepayer funds allocated to demand response for three-year periods, and has approved nearly $1 billion for the last three-year cycle, from 2011 to 2013 (see Appendix B, "California's Demand Response Programs: Historical Data," on page 14).

The other major state funding for demand response came from the CEC's Public Interest Energy Research funds, and these funds were used for the research and demonstration of new demand response technology. According to the CEC, it has awarded more than $22 million since January 2005 to demand response projects; more than half has gone to the Demand Response Research Center at Lawrence Berkeley National Laboratory.

With this research funding, the Lawrence Berkeley National Laboratory developed a communication infrastructure called Open Automated Demand Response (OpenADR), which provides a uniform protocol for aggregators, utilities, and energy users for sending signals about energy use and management. In 2007 the CPUC required California's three investor-owned utilities to offer OpenADR-based programs.

California's demand response programs are offered for residential and commercial customers and include the following programs:

- Aggregator-Managed Programs
- Agricultural and Pumping Interruptible Program
- Air Conditioning Cycling or Reduction
- Automated Demand Response (Auto-DR) Programs
- Base Interruptible Program (BIP)
- Capacity Bidding Programs
- Demand Bidding Programs
- Peak-Time Rebates or Critical Peak Pricing
- Time-of-Use (TOU) rates

For a complete list of the state's demand response programs, see Appendix C, "California's Demand Response Programs: 2014 Megawatt (MW) Forecast," on page 15. And for information on the governor of California's executive order to state agencies to participate in these programs, see "Energy Conservation: California's Governor Ordered Green Building Practices for State Agencies, Including Using Demand Response Programs," on the opposite page.

Some demand response programs are embedded within other demand response programs. For example, customers enrolled in demand response programs with Auto-DR technology (used to automatically respond to signals to reduce energy loads without a customer taking any action) are offered a financial incentive to use this technology. Auto-DR works via wire or wireless controls that can control, for instance, the dimming of lights or adjustments to air conditioning systems. It also can include energy management software or hardware.

Customers may select the demand response programs most appropriate for them, and the CPUC allows those participating in a peak-pricing program to also participate in either the Capacity Bidding Program or BIP. California's programs are divided into those

ENERGY CONSERVATION

California's Governor Ordered Green Building Practices for State Agencies, Including Using Demand Response Programs

California Governor Edmund G. Brown, Jr., issued Executive Order B-18-12 on April 25, 2012, requiring state government agencies to implement green building practices in state buildings. His order was accompanied by a Green Building Action Plan for facilities owned, funded, or leased by the state. Among its requirements, the order directs state agencies to "participate in 'demand response' programs to obtain financial benefits for reducing peak electrical loads when called upon, to the maximum extent that is cost-effective for each state-owned or leased facility, and does not materially adversely affect agency operations."

Approximately 1.2 million megawatt hours of electricity—with an estimated 720-megawatt peak load—was used by California's state buildings in 2013. Many state agencies, including the Department of Corrections and Rehabilitation, Department of Transportation, Department of Motor Vehicles, Department of General Services, California Air Resources Board, and California Highway Patrol, are participating in utility demand response programs with Pacific Gas and Electric (PG&E), Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), and Sacramento Municipal Utility District (SMUD). These state agencies are involved in programs such as critical peak pricing, aggregator-managed programs, demand bidding programs, and automated demand response programs (for program descriptions, see pages 8 to 10).

California does not maintain a list of state buildings enrolled in demand response programs or calculate the total energy load that could be shed by participating in such programs, although the state has the potential to shed between 36 to 72 megawatts per peak-load event.

When monitoring progress of the governor's executive order, it would be useful for the state to attempt to quantify its total demand-response reduction potential and calculate whether —and by how much—demand response incentives are saving the state in energy costs. Such information could be analyzed and published in the California Energy Commission's Integrated Energy Policy Report to show whether state agencies are participating in the most appropriate demand response programs and, if they are, whether they are successfully managing their participation to ensure they are providing the most benefits to California's power grid and taxpayers.

that allow participants to be notified either one day ahead or the day of the need to activate their demand response programs. Flex Alert is a California demand response marketing campaign designed to educate the public about the need for energy conservation in the summer. The marketing ranges from providing general educational information to issuing alerts when CAISO believes energy reductions are necessary due to heat waves, wildfires, major power plant outages, or transmission problems. The alerts urgently request Californians to shift energy usage to off-peak hours to avoid possible blackouts.

The paid advertising portion of Flex Alert is authorized by the CPUC, funded by the investor-owned utilities, and managed by a marketing and outreach firm under contract with the investor-owned utilities. Broadcast and online advertising informs consumers about how and when to conserve electricity.

A 2013 evaluation of Flex Alert found it produced "no statistically significant reductions in energy consumption."[6] However, Flex Alert's effectiveness is difficult to assess because the alerts might be triggered in multiple service areas or just portions of service areas, and customers who are more likely to respond to an alert often are enrolled in other demand response programs that also are asking them to reduce their energy load during a peak event, such as a heat wave.

Base Interruptible Program (BIP) is the largest demand response program, and pays large industrial energy consumers to turn off their power when called by the utility. As of December 2013, it has been used for seven "real" events in California in the last nine years.[7]

This program has cost California ratepayers approximately $837 million over the last nine years and accounted for 36 percent of ratepayer funds authorized by the CPUC for demand response (see Appendix B, "California's Demand Response Programs: Historical Data," on page 14). However, when called upon, the program produces significant results in energy reduction. For example, according to the CPUC, during the only test in 2012 in Southern California Edison (SCE) territory, the BIP produced 573 megawatts of load reductions (enough power for about 118,000 homes), which was 59 megawatts more (power for approximately 12,000 homes) than the day-ahead forecast, and more than three times the load reduction of any other SCE program that year.

In the current BIP model, utilities turn to the BIP as a last resort; it is used only after CAISO has called an emergency. The BIP is counted for Resource Adequacy program credit, but according to the CPUC: "Unlike all other power that counts for Resource Adequacy, the California Independent System Operator currently procures costly 'exceptional dispatch energy or capacity' before using this energy resource, a practice that has led to charges that ratepayers 'pay twice' for this power."[8]

The CPUC adopted a settlement agreement between CAISO, the California Large Energy Consumers Association, utilities, aggregators, and ratepayer advocates that will require triggering the BIP prior to CAISO canvassing neighboring balancing authorities for any available energy/capacity. The Federal Energy Regulatory Commission must give its approval to the CPUC decision—which is pending—before it can be implemented. The Office of

Ratepayer Advocates asserts the settlement was not strong enough, and the BIP should be called prior to CAISO procuring costly exceptional dispatch energy or capacity within its own balancing authority.

Policymakers should ask whether more than one-third of funds authorized for demand response should be used on a program that currently provides limited ratepayer benefits. Or should those ratepayer funds be used to create programs that could be triggered more often and provide similarly significant reductions? In addition, how will the settlement affect the use of the BIP and the ratepayers' benefits?

Peak-Time Rebates and Critical Peak Pricing are demand response programs that offer price rebates to residential and commercial customers for reducing their energy loads at peak energy times. The CPUC's assessment of these programs in 2012 found that some utilities failed to notify customers they were in the program. All of their customers with a smart meter automatically were included in the program. Customers also were sent notices about the demand response program (regardless of whether they had expressed interest in the program) and were given energy bill credits without significantly impacting their energy load.[9] In SCE territory, "95 percent of all incentives were paid to customers who either were not expected to or did not reduce load significantly," according to the CPUC.

Air Conditioning Cycling or Reduction is an opt-in program that gives customers a rebate or discount for allowing their utility company to cycle off or adjust their air conditioners during peak energy periods. However, some customers have complained that having their air conditioners shut off during peak-heat hours resulted in uncomfortable temperatures. In addition, when air conditioners were shut off for short periods of time (such as a couple of hours), a "rebound effect" occurred when they were turned back on by the utility because customers used even more energy once power was restored by adjusting their air conditioners —which negated the benefit of the overall program.[10]

Pacific Gas and Electric's (PG&E) SmartAC demand response program does not shut off air conditioners; instead, thermostats are adjusted by a few degrees during peak-use periods. Adjustments like this rather than cycling (or shutting off air conditioners) could eliminate the rebound effect and minimize uncomfortable temperatures.

Demand Bidding and Capacity Bidding programs allow nonresidential customers to bid on an amount of energy they are willing to reduce during a demand response event. The two programs vary by how far in advance customers must make their bid, how far in advance they are notified of an event, and whether there are penalties (and the amount of those penalties) if they do not deliver on their energy-savings agreements.

The Demand Bidding Program notifies participants one day ahead of an event, with no consequences for underperforming bids. Participants are financially compensated based on the amount of kilowatt hours (kWh) they reduced their energy.

In the Capacity Bidding Program, participants are paid a standby (or "capacity") payment, whether or not the program needs to be triggered. The program has a day-of and a one-day-ahead notification option, and either capacity payment adjustments or penalties, depending on the level of underperformance. According to the CPUC, SCE's day-of Capacity Bidding Program showed good performance in meeting its forecasted energy reductions in the summer of 2012. Other Demand Bidding and Capacity Bidding programs showed mixed results because they were not always able to deliver the forecasted energy reductions.

Aggregators and energy managers also play an important role in determining ways to shed load without harming productivity and a commercial energy customer's bottom line. Aggregators assess residential and commercial customers' energy use and assist them by using their software and technology to respond to signals to reduce energy consumption. Then the aggregators bundle their customers' entire load-shedding capabilities in the affected service territory and provide a contracted utility with an aggregate amount of energy that can be reduced, if necessary, during peak usage times.

Aggregators can assist utilities primarily by handling program design; however, utilities that have contracted with the aggregators must monitor the aggregators' successes and failures to ensure accountability. The CPUC's analysis of aggregator programs did not assess the programs specifically using aggregation, but SCE had both good and poorly performing programs that used aggregators. More research should be conducted to ensure all aggregator programs perform well.

Time-of-Use (TOU) rates are demand response programs that allow customers to opt in to high energy rates during peak usage times and lower rates during nonpeak times. Customers may use TOU rates and simultaneously participate in other demand response programs.

California Assembly Bill 327 (Perea, Chapter 611, Statutes of 2013) set a timetable and conditions for TOU rates. According to the September 9, 2013, California State Senate floor analysis, this bill enacted the following:

> Deletes the current restrictions on time-of-use (TOU) pricing and instead allows the PUC, beginning January 1, 2018, to require or authorize an investor-owned utility (IOU) to use default TOU pricing for residential customers. The TOU pricing will be subject to specified conditions, including that it not cause unreasonable hardship for senior citizens or economically vulnerable customers in hot climate zones, that the customer be provided with interval usage data before being subject to the TOU rates, and that residential customers have the option to not receive TOU rates without being subject to additional charges. Certain residential customers, such as those receiving a medical baseline allowance, will be exempt from any default TOU pricing.

Utilities offer voluntary TOU rates for nonresidential and occasionally for residential customers. For example, PG&E's SmartRate program offers the following:

> The plan gives customers a general price reduction of three to four cents per kilowatt hour from June through September. On a few hot afternoons during the warm-weather season, when demand is especially high, the rate temporarily increases by 60 cents per kilowatt hour to encourage customers to conserve and shift energy use outside of peak times. At most, only 15 SmartDays are called each season—and never on weekends or holidays.

As of spring 2014 there were approximately 120,000 participants in PG&E's SmartRate program (there are about 5.3 million PG&E electric customers in the state).

Peak or TOU rates may offer a simpler way of incentivizing demand response programs. Many incentive programs attempt to model the energy use that would have occurred without a demand response program, then measure the actual energy used by customers so either they will be rewarded for demand reduction or assessed a nonperformance penalty. Yet it is difficult to measure how much energy would have been used without a demand response program in place, and therefore difficult to assess accurately how much energy savings a customer has had as a result of a demand response program. In fact, a CPUC analysis found that demand response program operators could not predict accurately by how much their programs could reduce energy loads.[11]

If financial incentives were built into the pricing of electricity, customers would pay more for the electricity they use during peak-usage hours, and utilities would not have to determine how much energy the customers would have used without the program. Yet the California State Legislature has expressed concern that charging high prices for electricity during peak times could negatively impact economically vulnerable customers in hot climate zones.

Currently, programs are limited to opt-in demand response, and the CPUC is focused on offering nonresidential TOU rates. But more studies are needed on the effects of automated demand response and aggregators, and how residential customers can respond to peak-time pricing without sacrificing comfort or safety.

Coordination with CAISO on demand response programs has been lacking. According to the CPUC, "Unlike other generation resources, currently [demand response] is not integrated in the CAISO's wholesale energy market."[12] Therefore, when the utility triggers a demand response program, that program will not be visible to CAISO's real-time dispatcher for use in an emergency, which limits CAISO's ability to use demand response to maintain grid stability.

California ratepayers invest significant sums of money in demand response programs to avoid generation costs and provide a more reliable grid; however, California's demand response programs have had mixed results, and their benefits to the grid are unclear. The largest and most expensive program, the BIP, is used infrequently. Other programs reward customers who have not intentionally reduced their energy load. And when customers successfully reduce their load, sometimes there are rebound effects that are counterproductive to a program's goals.

RECOMMENDATIONS FOR STATE POLICYMAKERS

Demand Response Programs Could Help California Use Energy More Effectively

The following recommendations provide California's policymakers ways to assess and improve what is widely considered the state's most promising energy conservation tool: demand response programs.

> Monitor actions modifying demand response programs by the California Independent System Operator (CAISO), California Energy Commission (CEC), California Public Utilities Commission (CPUC), and utilities in the state, and follow any approvals required by the Federal Energy Regulatory Commission.

> Avoid mistakes made in past demand response programs—such as programs that do not provide the benefits of consistent load modification or the responsiveness of a supply-side resource—in the CPUC's new pilot programs. These programs eventually should be cost-effective, while attracting significant participation.

> Require the CPUC and CAISO to report to the California State Legislature on the implementation of Electric Rule 24 (recently established rules for participating in the CAISO market).

> Require the CPUC to assess aggregator programs to determine best practices for consistent performance.

> Require some pilot programs to demonstrate both the upward and downward adjustment of power to better integrate renewable power.

> Educate residential customers and empower them to respond to peak-time pricing without sacrificing comfort or safety, as the Time-of-Use (TOU) rates could become mandatory.

> Update the CPUC's goal of meeting 5 percent of the system's annual peak-energy demand through demand response programs by 2007; when setting new concrete goals, define what the programs should accomplish when modifying energy loads or supplying demand reduction as an energy resource in California.

In addition, due to a lack of coordination with CAISO, demand response programs are not used when balancing the grid.

Many of these problems have been recognized by utilities, regulators, and grid operators, and steps are being taken to try to correct them. On September 19, 2013, the CPUC adopted an order instituting rulemaking to attempt to address these problems, but it remains to be seen if the promise of demand response will be realized.

The CPUC will continue to fund the existing programs for the next two years, although ratepayer advocates and CAISO do not believe the current demand response programs should be continued for two years without changes and new procurement and delivery models. As part of the bridge-funding decision, the CPUC is funding several pilot programs, including a "living pilot" program by SCE to demonstrate and study demand response programs. Furthermore, the CPUC has just finalized Electric Rule 24, which has set rules for participating in demand response programs in the CAISO market.

What Are the Next Steps?

Significant work remains to ensure demand response programs are consistently shaping California's energy load in a beneficial way—or that the demand response programs satisfy energy needs as a supply-side resource. It is unclear whether the large portions of ratepayer funds dedicated to these programs are providing ratepayer benefits, or whether they are consistently enhancing reliability or avoiding use of more expensive and polluting power.

California's demand response programs must provide the right amount of energy savings, or increased energy demand, at the right place and at the right time. When shaping load, the response must be consistent over time by moving energy demand every time the load pattern occurs. When acting as a resource, the demand response program must be able to reduce demand whenever a reduction is needed, just as, for example, a peaker power plant can provide capacity on demand in a way that meets CAISO's system requirements.

As California faces increasingly serious energy challenges—such as the recent closure of San Onofre Nuclear Generating Station (SONGS), the upcoming once-through cooling deadlines, and the integration of more renewable energy—policymakers should assess whether the framework is in place to ensure the state's energy regulators are using their limited time and ratepayers' limited resources effectively and expeditiously to bring about benefits from demand response programs (see "Recommendations for State Policymakers: Demand Response Programs Could Help California Use Energy More Effectively," on the opposite page).

The CEC, CPUC, and CAISO are working toward improving California's demand response programs and much remains to be accomplished. It is unclear whether the problems with the state's programs can be resolved in the near future, yet if they are properly implemented, demand response programs could provide an extremely useful and cost-effective way to use California's energy resources.

APPENDIX A

U.S. Demand-Response Resource Potential at Independent System Operators and Regional Transmission Organizations

Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs)	2011		2012	
	Demand Response (megawatts)	Percent of Peak Demand	Demand Response (megawatts)	Percent of Peak Demand
California ISO (CAISO)	2,270	5%	2,430	5.2%
Electric Reliability Council of Texas (ERCOT)	1,570	2.3%	1,750	2.6%
ISO New England, Inc. (ISO-NE)	1,231	4.4%	2,769	10.7%
Midcontinent Independent System Operator (MISO)	9,529	9.2%	7,197	7.3%
New York Independent System Operator (NYISO)	2,247	6.6%	1,888	5.8%
PJM Interconnection, LLC (PJM)	14,127	8.9%	10,825	7%
Southwest Power Pool, Inc. (SPP)	1,514	3.2%	1,444	3.1%
Total ISOs / RTOs	**32,488**	**6.7%**	**28,303**	**6%**

Source: Federal Energy Regulatory Commission, October 2013

APPENDIX B

California's Demand Response (DR) Programs: Historical Data

UTILITIES	2005	2006	2007	2008	2009	2010	2011	2012	2013
TOTAL DEMAND RESPONSE PROGRAM COSTS (in millions of dollars)									
PG&E	$47	$50	$39	$67	$62	$56	$63	$62	$55
SCE	$146	$134	$147	$174	$175	$183	$193	$245	$230
SDG&E	$12	$8	$15	$20	$19	$25	$29	$38	$15
Total	**$205**	**$193**	**$201**	**$261**	**$256**	**$265**	**$284**	**$345**	**$301**
BASE INTERRUPTIBLE PROGRAM (BIP) COSTS (in millions of dollars)									
PG&E	$28	$35	$23	$23	$19	$19	$20	$24	$21
SCE	$66	$78	$54	$68	$60	$71	$72	$76	$77
SDG&E	$0.02	$0.06	$0.15	$0.33	$0.64	$1.3	$1.2	$1	$0.4
Total	**$93**	**$113**	**$78**	**$91**	**$80**	**$91**	**$93**	**$100**	**$98**
Percentage of Total DR Costs	45%	58%	39%	35%	31%	35%	33%	29%	32%
NUMBER OF BASE INTERRUPTIBLE PROGRAM (BIP) EVENTS									
PG&E		1 real	1 real	1 test	1 test	1 test	1 test & 1 real	1 test	1 test & 1 re-test
SCE	1 real	1 real			1 test		1 test	1 test	1 test
SDG&E		1 real	1 real			1 test	1 test	1 test	1 test
SDG&E DEMAND BIDDING PROGRAM (U.S. NAVY) EVENT									
SDG&E									1 real

Source: CPUC Energy Division

Note: Totals and percentages are rounded figures.

APPENDIX C

California's Demand Response Programs: 2014 Megawatt (MW) Forecast

PG&E NONRESIDENTIAL	MW	PG&E RESIDENTIAL	MW
Base Interruptible Program	276	Air Conditioning Cycling	82
Air Conditioning Cycling	3	Peak-Day Pricing[2]	16
Aggregator-Managed Portfolio (Day Ahead)[1]	85		
Aggregator-Managed Portfolio (Day-Of)[1]	182		
Demand Bidding Program	3		
Capacity Bidding Program (Day-Of)	29		
Capacity Bidding Program (Day Ahead)	20		
Peak-Day Pricing[2]	30		
PG&E Nonresidential TOTAL	**627**	**PG&E Residential TOTAL**	**98**

SCE NONRESIDENTIAL	MW	SCE RESIDENTIAL	MW
Base Interruptible Program	626	Air Conditioning Cycling[3]	294
Agricultural and Pumping Interruptible Program	63	Peak-Time Rebate[4]	6
Air Conditioning Cycling[3]	80		
Demand Response Contracts[5] (Day Ahead)	17		
Demand Response Contracts[5] (Day-Of)	142		
Demand Bidding Program	4		
Capacity Bidding Program (Day-Of)	11		
Capacity Bidding Program (Day Ahead)	0		
Critical-Peak Pricing	19		
SCE Nonresidential TOTAL	**962**	**SCE Residential TOTAL**	**300**

SDG&E NONRESIDENTIAL	MW	SDG&E RESIDENTIAL	MW
Base Interruptible Program	1	Air Conditioning Cycling[6]	12
Air Conditioning Cycling[6]	3	Peak-Time Rebate[7]	4
Demand Bidding Program	5		
Capacity Bidding Program (Day-Of)	10		
Capacity Bidding Program (Day Ahead)	8		
Critical-Peak Pricing	34		
SDG&E Nonresidential TOTAL	**61**	**SDG&E Residential TOTAL**	**16**

Source: CPUC Energy Division

1 Day Ahead means participants are notified to reduce their energy load the day prior to the day it is needed by the utility; Day-Of means they are notified on the same day the load drop is needed.

2 Peak-Day Pricing is PG&E's (Pacific Gas & Electric's) market name for its Critical-Peak Pricing program.

3 SCE's (Southern California Edison's) Air Conditioning Cycling program is marketed under the name Summer Discount Plan.

4 SCE's Peak-Time Rebate program is marketed under the name Save Power Day.

5 SCE's Demand Response Contracts are bilateral agreements with third-party aggregators, similar to PG&E's Aggregator-Managed Portfolio.

6 SDG&E's (San Diego Gas & Electric's) Air Conditioning Cycling program is marketed under the name Summer Saver.

7 SDG&E's Peak-Time Rebate program is marketed under the name Reduce Your Use.

Endnotes

1 Christopher Ashley, L. Holmes, and G. Wikler, "Using More Energy Can Be a Good Thing: C&I Loads as a Balancing Resource for Intermittent Renewable Energy," EnerNOC Utility Solutions, white paper, presented at the 2013 American Council for an Energy-Efficient Economy (ACEEE) Summer Study on Energy Efficiency in Industry, Niagara Falls, New York, July 25, 2013.

2 Resource Adequacy is a California Public Utilities Commission program that determines the amount of energy-generation capacity needed to maintain reliability, based on forecasts provided by the California Energy Commission and the California Independent System Operator (CAISO). The program also mandates load-serving entities (LSEs) to procure the capacity needed and to supply it to the CAISO energy markets. LSEs provide plans to the California Public Utilities Commission, California Energy Commission, and CAISO on how they will meet their Resource Adequacy obligations; LSEs face penalties if they do not comply with the requirements.

3 "Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements," California Public Utilities Commission, Demand Response Rulemaking 13-09-011, September 25, 2013, p. 7.

4 "Order Approving Stipulation and Consent Agreement," U.S. Federal Energy Regulatory Commission, Docket Number IN12-11-000, issued March 22, 2013, p. 2.

5 "Power Trends 2013: Alternating Currents," New York Independent System Operator, May 30, 2013, p. 11.

6 Steven D. Braithwait, D. Hansen, and M. Hilbrink, "2013 Impact Evaluation of California's Flex Alert Demand Response Program," CALMAC Study ID SCE0343.01, Christensen Associates Energy Consulting, Madison, Wisconsin, February 28, 2014, p. 3.

7 The real events tally does not include U.S. Navy-related events.

8 "Decision Adopting Settlement Agreement on Phase 3 Issues Pertaining to Emergency Triggered Demand Response Programs," California Public Utilities Commission, Rulemaking 07-01-042, Decision 10-06-034, June 24, 2010, p. 2.

9 "Lessons Learned From Summer 2012: Southern California Investor-Owned Utilities' Demand Response Programs," California Public Utilities Commission, Commission Staff Report, May 1, 2013, p. 41.

10 Ibid., p. 19.

11 Ibid., p. 1.

12 Ibid., p. 75.

Written by Michael W. Jarred. The California Senate Office of Research is a nonpartisan office charged with serving the research needs of the California State Senate and assisting Senate members and committees with the development of effective public policy. It was established by the Senate Rules Committee in 1969. For more information and copies of this report, please visit **www.sen.ca.gov/sor** or call **(916) 651-1500.**