A Vision of Demand Response – 2016

Envision a journey about 10 years into a future where demand response is actually integrated into the policies, standards, and operating practices of electric utilities. Here's a bottom-up view of how demand response actually works, as seen through the eyes of typical customers, system operators, utilities, and regulators.

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Adding a new generator to a utility resource pool is a complex process that impacts forecasting, grid management, system dispatch, and pricing. So it often comes as a surprise to most resource planners when they learn that adding demand response involves even greater complexity. Unlike any other utility resource, demand response requires the simultaneous integration of conventional system supply and an even more complex range of marketing, pricing, educational, and customer service changes.

Over the last 30 years demand response has not realized its potential primarily because it has not been integrated into the basic utility operating and service structure. It is has always been easier for regulators and utilities alike to think of demand response as separate, independent programs that can be added one day and dropped the next. Why do most demand response ''programs'' limit which customers and which loads can participate? Isn't a kilowatt at 2:00 p.m. worth the same regardless of whether it comes from an air conditioner or lightbulb? One answer: it is easier and cheaper to pay for participation than to install the meters and implement the rates necessary to

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pay for performance. It does not seem to matter that the integrated approach works better and is a more permanent and equitable solution. The real problems with demand response come when utilities try to ''operate'' the customer like a power plant. What you get is another ineffective effort with limited potential and an even shorter life.

So what happens when demand response is fully integrated into the utility planning and operating structure? What happens when demand response is actually supported by pricing, operating policies, and building and appliance standards? What happens if demand response, like energy efficiency, becomes a condition of service?

Like the top-down vision presented elsewhere in this issue in Ahmad Faruqui's ''The Long View of Dynamic Pricing and Demand Response,'' let's envision another journey about 10 years into a future where demand response is actually integrated into the policies, standards, and operating practices of electric utilities. However, let's use this trip to create a bottom-up view and see how demand response actually works as seen through the eyes of typical customers, system operators, utilities, and regulators. For simplicity's sake, we'll focus on California because, in many respects, this is its vision.

All of the technological and engineering features presented in the vision that follows are feasible today. With the right incentives, regulators could unleash a market of technology and service providers that will almost immediately provide entirely new customer and utility resources. The policies and standards are also feasible; however, they require political motivation, which is too often constrained by a lack of vision. So here's a vision of demand response. Let's see where it leads.

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I. 2006 California Policies and Standards Change Everything

For California, regulatory decisions in 2006 made advanced metering infrastructure (AMI), critical peak pricing (CPP), and programmable communicating thermostats (PCT) the defaults for all customers. This changed everything.

Demand response and energy efficiency were now fully integrated into all customer service agreements. The combined time-of-use and critical peak components of the CPP rate provided customers with new incentives to evaluate efficiency investments and simultaneously consider major appliance and other purchases to facilitate load shifting and reductions in response to price or reliability events. Almost immediately, regulators discovered several conflicting building design standards that prevented customers from integrating their efficiency and demand response options. More regulatory changes followed.

CPP eliminated the artificial boundaries and restrictive participation rules imposed by previous efficiency and demand response programs, rewarding customers for performance rather than program participation. Impacts were immediate and significant. Renters, seniors, low users and huge segments of the residential and small-commercial populations previously excluded from participating in conventional programs took advantage of the new incentives to make efficiency improvements and automate demand response. A tracking study confirmed that PCTs were producing substantial energy conservation as well as demand response impacts. Apparently the default lifestyle settings and automated demand response strategies in combination with CPP incentives increased the use of conventional thermostat setbacks from less than 20 percent to over 80 percent of the user population. So many customers were now avoiding the use of high-cost energy that utility costs stabilized more quickly than expected. Revenue requirements

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and rates dropped almost as quickly.

CPP rates also improved the return on investment and reduced the payback period for many critical lighting, HVAC, and alternative generation options so much that regulators refocused consumer incentives to overcome purchase resistance and financing rather than long-run cost effectiveness. Utility efficiency and demand response activities also changed. Because CPP embedded efficiency and demand response incentives in the tariff, utilities discontinued their program development and management activities and focused instead on customer education, information services, and vendor and product referral services – efforts to emphasize and assist customer adaptation to the CPP tariff.

Demand for PCTs, originally envisioned as a new construction initiative involving only a few hundred thousand customers a year, now was experiencing several hundred thousand retrofits each month. CPP tariffs fueled a land rush of customer demand for automation devices and services. Within a year of introduction, new versions of PCTs were flooding the market. Several manufacturers announced accelerated plans to further lower costs and improve capability by embedding controls directly in consumer appliances.

Follow-up studies concluded that customer price responsive capability under CPP tariffs consistently produced 6–8 percent reductions in summer peak system load in response to day-ahead notification. Voluntary reliability responsive capability under the CPP tariff was producing 12–18 percent reductions in summer system peak load in response to day-of notification. Emergency, non-overridable operations consistently produced 30–35 percent reductions in summer peak system load on selected feeders in high-temperature zones and 8–15 percent reductions in peak load on selected feeders in winter.

Demand for PCTs, envisioned as a new construction initiative, now was experiencing several hundred thousand of retrofits each month.

Within two years of adoption, the regulatory agencies formally modified utility outage management plans to incorporate the PCT non-overridable emergency capability. Automatically dispatching precisely targeted, brief, low-intensity restrictions on customer HVAC systems was clearly preferable to conventional rotating outages. The PCT substantially improved system protection capabilities.

Rotating geographic outages would very likely never occur again.

II. A Critical Peak Day: What a Residential Customer Sees

Meg A. Watt, a 78-year-old retired widow, does not like computers or automation. Although she was excited about moving into her new condominium in the Shady Acres Lawn Bowling and Mahjong Retirement Community, she is overwhelmed by this new programmable communicating thermostat and all of the other electronic equipment installed throughout her complex. Her old place in Idaho didn't have any of this fancy electronic stuff.

Unlike his mother, Meg's 42-year-old son Less was infatuated with technology. To reassure his mother he volunteered to help her move and setup her PCT. Less called the utility in advance to arrange service. The utility representative asked a few questions regarding his mother's basic lifestyle and home features and whether she qualified for any special medical or other exemptions. As a result of that call, they mailed Less an information packet and setup checklist.

9:05 a.m., Friday, July 1, 2016 A few minutes after Less and his mother arrived at her new condominium, he took her over to the wall where the PCT display was mounted and, using the checklist provided by the utility, proceeded to show her how it worked.

He explained that about 10 years ago the California regulators had adopted new default rate structures that charged customers

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a critical peak rate. During most months, her electric costs would be lower during late evening to early morning hours and higher during the mid- to late-afternoon period. When demand for energy ever got high enough to trigger an unreasonably high-cost situation or threatened the utility's ability to provide power, they would send out a radio signal alerting all customers to an impending critical peak price. Less explained that she would usually receive 12 to 24 hours' advanced notice, though emergencies could be called with no advanced notice – which was the reason customers used PCTs to automate their response.

Less explained to his mother that CPP turned out to be much better than most people first expected. Not only were CPP prices less than his old rate for about 85 percent of the year, but most people actually found CPP easier to understand. Meg now understood why Less fully automated his own home and business and why he pre-cooled his home on very hot days.

The utility checklist provided estimated billing information for his mother's new condo, based on information Less provided during his phone call to activate her account. They estimated that his mother's new home would probably be a ''low user.'' As a result she would get a bill each month that would charge her either the subsidized capped rate or the CPP rate, whichever was lower. The utility called this the Low Bill Guarantee Option.

Less explained that her PCT was actually receiving continuous price signals from her utility. The PCT was programmed to identify critical peak price and emergency signals and automatically make minor adjustments to her comfort settings based on her preferences. Less described what each of the LED lights and icons on her PCT display meant. The yellow light, which was currently lit, indicated that the thermostat was active, working properly and currently receiving a utility test/price signal. He showed her the little sticker attached to the thermostat that provided instructions for calling the manufacturer if the yellow light should ever go out or if the thermostat malfunctioned in any other way.

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Less also explained to his mother that she had three options to choose from in setting up her PCT:

Option 1: Live with the Default Settings – If she did nothing, the PCT installed defaults would automatically raise her thermostat setting by 2 degrees in summer or lower it by the same amount winter in response to the critical peak prices.

Option 2: Modify the Default Lifestyle Settings – Using the setup button, Less scrolled through several PCT stored lifestyle settings. Lifestyle settings provided common work, vacation, and other operating schedules. Meg's defaults were pre-programmed by the builder specifically for a typical retirement weekday and weekend ''at home'' schedule, with the minimum critical peak price response. Meg could easily change the schedule to suit her needs or to increase or decrease her critical peak savings on her electric bill. Less also showed Meg that she could leave the automatic price response program alone and just push the PCT override button if she ever became uncomfortable or inconvenienced during a pricing event. Pushing a single button to override a pricing event meant she might have to pay a higher price for those hours, but the Low Bill Guarantee Option provided reasonable financial protection.

Option 3: Disable the Stage 2 Emergency Setting – According to the checklist, this option was limited to individuals with health and other disabilities who might be adversely impacted by any of the emergency non-overridable PCT interruptions. Meg qualified for the exemption based on information Less provided during his original service call. The checklist included a highlighted box with what looked like a special bar code printed in one corner. Less was directed to hold the bar code within six inches of the PCT, hold down the override button and wait for an acknowledgement signal. According to the checklist, the bar code was really a printed radio frequency identification tag that was programmed for a one-time exemption.

9:20 a.m., Friday, July 1, 2016 Less and his mother completed the checklist. As they were walking away one of the PCT indicator lights started flashing. Meg looked at Less and asked if that was something he did or was that a signal from the utility that announcing a forthcoming critical peak price day.

Less pulled out his pocket communicator, a small hybrid device a little larger than a deck of cards that included voice, video, calendaring, email, several entertainment options, and electronic e-commerce applications. The top portion of the display was flashing with a critical peak alert for Less' house that was located several miles away. Less showed his mother the flashing message that confirmed a pending critical peak alert. Less mentioned that he had programmed his home systems, through his private energy management service, to forward all critical messages to him via his pocket communicator.

10:05 a.m., Friday, July 1, 2016 Less went home and Meg settled in to her new home. While reading the local newspaper she noticed a small banner in the upper right corner of the front page announcing that today would be a critical peak day. There was even a reference to a later section of the newspaper that provided a ''Helpful Hints'' list of things people could do to save money. The TV weather report on her refrigerator monitor indicated that the heat wave was continuing, forecasting another day with temperatures exceeding 100 °F. As she watched the weather report Meg noticed a similar ''Critical Peak Alert'' banner superimposed in a corner of the TV screen.

As she watched the weather report, Meg noticed a ''Critical Peak Alert'' banner superimposed in a corner of the TV screen.

When she checked her PCT she noticed that the light was still flashing. She was still a little uncertain regarding how all this new electronic stuff might work, but the information provided by the newspaper and local TV station seemed to demonstrate a rather comforting level of coordination. It seemed like the whole community was pulling together to help keep down costs and avoid problems. Meg was feeling pretty comfortable with her new home.

11:30 a.m., Friday, July 1, 2016 Meg had just returned from the local grocery store and was unpacking when she heard a brief ''beep'' that appeared to come from her PCT. She noticed that the indicator light had stopped flashing and was now fully lit. According to Less, this meant that the critical peak prices were now in effect, which was supposed to trigger an automatic response from her air conditioning system. From the checklist that Less left with her she knew that her thermostat was set to 75° but now it read 77°. Meg was impressed. The thermostat had automatically responded just as Less had described. Meg went back to unpacking her groceries but mentally reminded herself to take another look a little later to make sure everything was still working right.

4:00 p.m., Friday, July 1, 2016 While entertaining several of her new neighbors, Meg heard another beep coming from her PCT. When she checked, the emergency warning light was flashing. One of Meg's new neighbors explained that the local utility must be having a problem, something called a Stage 1 system emergency. One of Meg's new neighbors then stated that she had programmed her thermostat to go all the way up to 80° during these critical peak events because of the money it saved on her monthly bill. She said, ''When it gets too warm, I just go to the clubhouse or mall for a few hours.'' Meg decided to wait and see whether her home would become uncomfortable.

4:03 p.m., Friday, July 1, 2016 Just as she was about to rejoin her new friends, there was another

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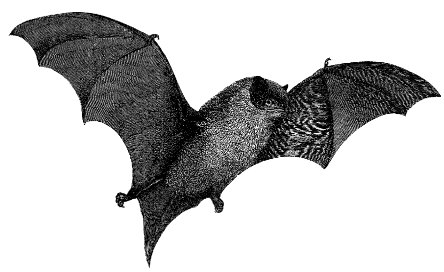
beep from the PCT. Now the emergency light stopped flashing and stayed lit. Meg knew from Less that this meant there was now a much more severe Stage 2 emergency. However, Meg also noticed that although her PCT setting did not change from 77° the numbers were now flashing. One of her guests said something must be wrong with Meg's PCT because when she gets a solid emergency light her PCT displays a flashing emergency symbol instead of a temperature setting. One of Meg's other guests chimed in and said, ''The flashing temperature setting means that Meg must have a medical exemption.'' Meg confirmed that indeed that was the case. Once Meg's neighbors figured out that a Stage 2 emergency had been called, they also realized that their air conditioning systems would automatically be locked out until the utility problems were corrected. None of Meg's neighbors had exemptions. Seeing that they were reluctant to return to homes that would soon be getting a little uncomfortable, Meg invited her guests to stay a little longer. They unanimously accepted.

Then they all started talking about how complex all this technology stuff was. Meg was still confused and amazed over how what looked like a bar code on a piece of paper could actually be a miniature radio.

5:50 p.m., Friday, July 1, 2016 Meg's first mahjong game was breaking up and her new neighbors were starting to leave when there was another beep from her PCT. The yellow light was now the only one of the three that was still lit. All of the warning lights were off. Meg's PCT was registering an internal reading of 77° but her setting was now back to 75°. Apparently both the critical peak and emergency situations were over. Meg and her neighbors just shrugged and went about their business.



III. A Critical Peak Day: What a Commercial Customer Sees

Mega Office is one of the largest high-rise commercial office complexes in the downtown area. It provides premium office, conference, and retail space for top financial, legal, and other service organizations. In 2005 Mega Office volunteered to participate in a field trial for a demand response program referred to as ''AutoDR.'' AutoDR provided secure Internet price and reliability signals to a gateway linked into their building energy management and control system (EMCS). These signals automatically triggered facility management and equipment strategies programmed by Mega Office's own supervisory staff. Participation in the AutoDR program turned out to be much more productive than they ever anticipated.

During the AutoDR setup process all of Mega Office environmental, internal operating systems, and energy management systems were tuned up and recalibrated. They discovered a number of operating inefficiencies that when corrected resulted in substantial energy and bill savings. They also identified a menu of operating strategies to support reliability and price-based demand response options. The strategies were programmed into their EMCS. AutoDR worked so well that Mega Office expanded their automated controls to include more lighting and air handling equipment.

Yesterday, the EMCS logged in a utility-provided CPP alert. Due to contractual requirements in its tenant leases, Mega Office price response strategies were designed to produce no more than a 10–15 percent reduction in facility load. Tests confirmed that these strategies could be dispatched without violating lease conditions or creating tenant discomfort or inconvenience. Mega Office's emergency response strategies were designed to produce a much larger (20–50 percent) but shorter-duration reduction in facility load. Supplemental ISO emergency incentives made

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emergency load reductions economically very attractive.

Utility notification messages late Thursday afternoon confirmed a potential CPP for Friday, July 1 with an anticipated start time of 11:30 a.m. and duration of three hours. With a day-ahead warning, the building supervisor confirms the automatically activated AutoDR pre-cooling strategy for the following day. AutoDR control strategies were now determined from an internal EMCS menu based on weather forecasts and expected CPP operating times. Under the pre-cooling strategy, automated EMCS enthalpy controls would start bringing in outside air to pre-cool the eastern zones of the building during the early morning hours. Building HVAC systems would provide supplemental cooling based on weather forecasts to bring the zone temperatures to pre-defined set points that should be sufficient to let Mega Office substantially reduce demand through the peak period and coast through at least part of the anticipated late-afternoon critical peak hours.

5:30 a.m., Friday, July 1, 2016 Mega Office's building supervisor has been monitoring the pre-cooling effort that started about one hour earlier. Enthalpy controls are bringing in cooler outside air to lower internal building space temperatures from their standard 75° to 70°. The eastern-facing zones are being pre-cooled first because they get the morning sun. All remaining building zones will be rotated in until the pre-cooling routine shifts over to building mechanical systems sometime before 10:30 a.m.

8:30 a.m., Friday, July 1, 2016 The Mega Office facility has been pre-cooled to the target set point. Email alerts from its local utility appear on the supervisor display monitor confirming that today

will be a critical peak day with a projected start at 11:30 a.m.

10:00 a.m., Friday, July 1, 2016 Building mechanical systems are providing the first cooling to some of the eastern-facing retail areas, which are experiencing higher-than-expected foot traffic. The building EMS has settled into its normal peak-off peak building management pattern.

11:30 a.m., Friday, July 1, 2016 A message from the Mega Office utility alerts the building supervisor that the critical peak price is now in effect. The utility alert indicates that weather and system loading conditions may extend the CPP period from 2:30 to 3:30 p.m.

Mega Office AutoDR strategy had begun to slowly ramp down lighting levels in most of the building public and private areas starting at 11:00 a.m. so that by 11:30 a.m. most non-critical lighting is operating at about 65 percent of its regular load. Under the AutoDR operating strategy, cooling tower set points are raised, several of the less necessary elevator banks and all decorative lighting and fountains have been curtailed. According to the EMCS, building load is leveling off at between 88 and 90 percent of the previous day's load. Temperatures in portions of the eastern zones are beginning to rise above the normal set point target. Because of the critical peak, temperatures will be allowed to rise to 77°, or 2° above their normal set point. Forecasts project that building mechanical systems will ramp back to full capacity by 4:00 p.m.

2:30 p.m., Friday, July 1, 2016 Mega Office receives notification that CPP rates are being extended due to weather and system congestion problems until 4:00 p.m.

4:00 p.m., Friday, July 1, 2016 At 4:00 p.m. Mega Office receives an electronic Stage 1 emergency message from its local utility. The Stage 1 alert automatically triggers a Mega Office Phase-2 AutoDR energy management strategy. Additional banks of non-essential lighting are turned off while others are reduced to roughly 50 percent of their normal level. Cooling tower set points and interior temperatures are raised another 1°.

4:02 p.m., Friday, July 1, 2016 The Mega Office EMCS received a

 1040-6190/$–see front matter doi:/10.1016/j.tej.2006.08.008

priority Stage 2 emergency message. AutoDR EMCS routines automatically switched substantial portions of the Mega Office load to on-site gas-powered emergency generators, dropping the building load to roughly 45 percent of its normal 4:00 p.m. demand.

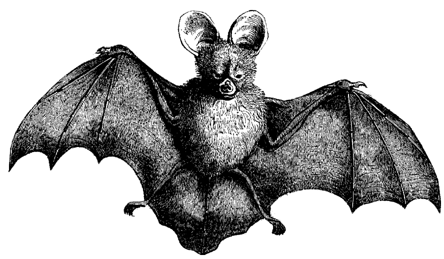
4:30 p.m., Friday, July 1, 2016 The end-of-day routine begins as approximately 20 percent of the building tenants headed home. Building loads started their normal late afternoon decline. By 5:30 p.m. approximately 40 percent of the building tenants are gone, load has declined substantially, interior temperatures have stabilized and the emergency generators are ratcheted back to about 50 percent of their previous operating level.

6:35 p.m., Friday, July 1, 2016 The Stage 2 alert ended, all the emergency generators are shut down, and Mega Office EMCS goes into a recovery mode. All interior temperatures and other building operating systems are back in full operation by 8:00 p.m.

IV. A Critical Peak Day: What the ISO Sees

Each morning, models linked into the real-time database maintained by the Statewide Power Management System (SPMS) produce reports comparing transmission, substation, and selected feeder loads for the previous five days with forecasted loads for the next three days. The SPMS is an advanced supervisory control and acquisition data systems (SCADA) application implemented as part of a major grid modernization effort. The SPMS was designed as a series of utility-owned and -operated independent systems and databases that are virtually linked through the Internet.

Analytical models at both the ISO and utilities continually



integrate and evaluate generator availability, maintenance schedules, and outage information together with weather, actual load, voltage and frequency, and measurements of other system harmonics into hierarchical reports to support resource trading desk and other system operating and emergency activities. The SPMS reports provided to ISO system engineers include substantially refined estimates of expected supply, demand and the status of reserves throughout the state.

Automated routines under the SPMS conduct daily system tests to calibrate PCT and AutoDR emergency capability by substation and select-feeder locations. Equivalent to the notch tests conducted for the original air conditioning load control programs in the late 1970s and early 1980s, daily tests randomly dispatch a test signal to temporarily drop each connected load and allow measurement by real-time metering located on each substation and feeder circuit. SPMS test signals are randomized to occur at different times each day.

The database of SPMS test results accumulated over the last five years provides the ISO and utilities with the capability to construct isograms that estimate the emergency load available by hour and temperature at each major feeder location. The database of isograms is integrated into emergency dispatch algorithms. This allows system operators to target and scale emergency load relief to specific feeder and delivery point needs.

Algorithms linked to real-time monitoring of each targeted distribution point provide a closed loop confirmation and adjustment function to assure achievement of emergency load objectives. Dynamic algorithms use isograms to automatically determine the optimum control strategy and customer grouping needs for each feeder. Control strategies balance the PCT temperature changes and available customer load necessary to protect the system and minimize customer impacts. With real-time monitoring, the SPMS can compare the actual load reductions achieved with the load reductions needed and instantaneously adjust strategies

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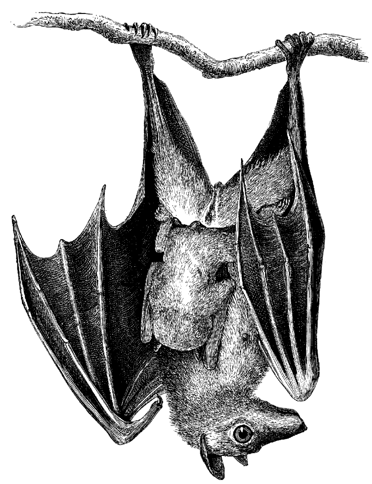
automatically upward or downward to maintain system balance. Because of the large amount of load under control, emergency operations only rarely result in temperature changes of more than one to two degrees during a typical two-hour event and generally no more than two to three degrees during a four-hour event.

10:00 a.m., Thursday, June 30, 2016 Due to restricted supply conditions, Cal ISO forecasts estimate 200–400 percent increases in peak hour prices for Friday afternoon, July 1, 2016. Reserves on Tuesday briefly dipped below 10 percent. With today's expected high temperatures and critical peak prices, forecasts don't look good for Friday. Reserves are projected to be very close to the 7 percent threshold and SPMS reports indicate that any additional forced outages would trigger a reliability event. SPMS monitoring shows that critical congestion has now spread out of the Southern Central Valley region into the entire Central Valley, the Southern desert, and throughout the entire LA basin.

Cal ISO system operating models estimate that customer price response will produce peak load reductions of 8–12 percent, which should be more than adequate to maintain system reserves. Continuously updated load and system harmonic data from the real-time SPMS confirm that up to 25 percent of targeted substation loads are available through the emergency PCT applications should supply and/or other system conditions worsen. Forecasts target and identify specific substations and distribution points where supply/congestion problems will be most severe.

ISO 24-hour price forecasts and a critical peak price alert for Friday, July 1, are automatically posted and dispatched via the Internet to the Reliability



Exchange. The Reliability Exchange is a secure Internet site maintained by the ISO that provides open access to price and reliability forecasts on a weekly, daily, and hourly basis accessible to energy utilities, consumers, and energy/demand response providers. Secure portions of the Reliability Exchange provide automatic notification and coordination between the investor-owned and municipal utilities and licensed third-party signal providers.

5:30 a.m., Friday, July 1, 2016 The ISO operations center is receiving continuous real-time updates from the SPMS. Real-time substation and feeder data, together with weather forecasts, monitored system harmonics, historical circuit loading, and current trading data produce a forecast of potential system cost, market price, and system reliability conditions for a range of geographical and critical transmission/distribution locations throughout the statewide electrical network. With a continuing heat wave, several forced outages and other supply constraints; the forecast anticipates potential critical price conditions for the next day during the later afternoon hours.

Several times each day the ISO provides each local utility with a critical peak status alert and detailed forecasts. Each local utility determines its own needs and then has the option to dispatch a critical peak alert through its own or other private communication providers.

9:05 a.m., Friday, July 1, 2016 Meg Watts' PCT was responding to a single secure Internet signal that originated over 400 miles away from the ISO to her local utility. The ISO critical peak price signal was automatically dispatched based on algorithms that balance the wholesale costs with other information regarding congestion for each monitored substation and distribution circuit. The ISO signal was received almost instantaneously by Meg's host utility and was instantaneously passed through to its critical peak broadcast system. Passing the critical peak signals through each utility allows local utilities to intervene and adjust the dispatch for any maintenance

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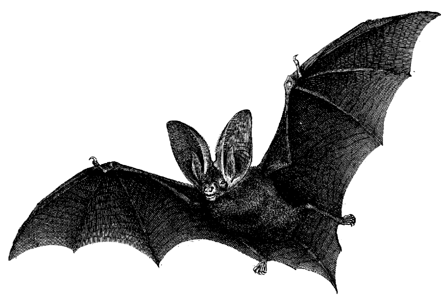
or other special activity that might be jeopardized by an untimely price or reliability signal. Utility operators had not flagged any of the target areas for intervention; consequently the ISO signal was passed through automatically without delay.

Within 3–5 seconds the critical peak price signals are received by approximately 1.5 million residences and businesses, representing approximately 12 GW of load. Price and reliability conditions were not yet considered severe. Isograms indicate that voluntary customer price response should provide more than sufficient load relief to mitigate current problems. Consequently the ISO dispatch was statistically targeted to dynamically configured groups of customers within the target area to produce a minimum 2° change in PCT setting at any customer site. ISO algorithms dynamically configure customer groups and the control intensity to just meet the system need. Real-time monitoring through the SPMS provided a closed-loop response to automatically adjust the control strategy up or down based on actual real-time customer response.

Critical peak price and reliability signals are received by each PCT and price-responsive device almost instantaneously; however, activation of the device response is internally randomized over a 15-minute period. Randomizing the start times of each customer device helps balance both the initial load impacts and returning load at the end of the control period. In emergencies the ISO or local utility can trigger an immediate, non-random instantaneous control strategy for all customer-controlled devices.

3:59 p.m., Friday, July 1, 2016 The SPMS registers a forced outage on a major supply point feeding the Southern central valley area. Algorithms at the ISO adjust for the loss of load by



instantaneously ramping up the customer price response signals. The ramping process during an emergency generates multiple radio activation signals that (1) automatically bypass local utility intervention and (2) instantaneously realign customer groups and synchronize another round of 2° temperature increases from all PCTs and other price-response devices.[1] This latest round of emergency signals also overrides the internal randomizing routines in customer control devices to intensify the load response. The dynamic realignment of the customer groups allows the ISO to focus price response on the most congested areas. Reserve margins are now below 7 percent in certain geographic areas but holding steady.

4:02 p.m., Friday, July 1, 2016 Another forced outage drops reserves below 5 percent, triggering a Stage 2 alert. This time ISO dispatch algorithms substantially ramp up the control algorithms to temporarily impose mandatory reliability overrides on all non-exempt customer PCT-controlled loads. In this case, a severe distribution problem requires the PCT loads in the target area to be locked out entirely for the duration of the event. Almost instantly, the SPMS registers an additional 2 GW of load relief on the impacted circuits, pushing system reserve margins back above 7 percent.

Simultaneously, local utility systems dispatch electronic warning messages to all major commercial and industrial customers as well as others who had signed up for the notification service. Announcements are automatically dispatched to all radio and television stations. Repair crews automatically receive information from both the utility AMI network and SPMS regarding isolated customer and distribution feeder outages. Utility crews receive emergency electronic work orders on Internet connected field tablets that direct them to specific GPS coordinates for each outage.

All forced outages are quickly resolved by emergency utility crews. By 5:45 p.m. power is restored to all customer locations. Declining commercial loads combined with voluntary

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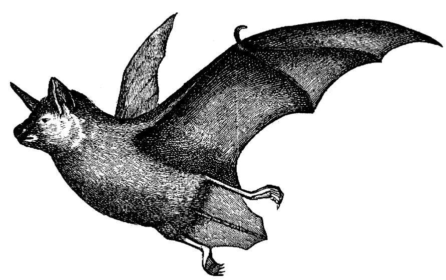
and mandatory price/reliability response brought reserve margins back to normal levels. Based on SPMS forecasts, refresher CPP price and reliability signals are discontinued at 5:50 p.m. Forecasts showed that customer loads will return to their normal local operating state starting around 6:30 p.m.

No additional outages are reported. Utility customer operating centers reported no significant increase in call volume.

V. A Critical Peak Day: What the Utility Sees

System-wide implementation of AMI together with development of the SPMS has provided the investor-owned and municipal utilities with a wide range of enhanced system operating and customer service applications. Customer information systems (CIS), enhanced billing, outage management, maintenance management, trading, and forecasting have all undergone major application changes.

A variety of customer information services have been introduced, including graphical bill analysis and subscription-based load data and cost analysis. One of the more innovative services is a wireless display that can be rented from utility and local community library facilities. Supplementary plug-interface and other devices can also be rented. These devices allow the customer to conduct their own end-use studies. The display provides customers with near real-time load monitoring and billing information for their account. Customers usually subscribe to this information service for one or two months at a time when they have a billing problem, unexplained usage patterns, or when replacing a major appliance. Embedded applications and



databases, accessible through the display device, can be used to help customers evaluate the potential bill impacts of various appliance upgrades and other efficiency alternatives. Applications allow customers to model the potential energy and cost impacts on their facility, to identify potential rebates, store locations, installers, and financing options. Reports can be downloaded to their own computer or mailed by the utility. Customers can also link into the same utility databases and applications using their own wireless displays or home computers and subscribe to the service for a nominal cost.

Daily, customer service representatives, distribution engineers, and trading staff review the forecasts of yesterday's operations along with 24-, 48- and 72-hour forecasts of weather and system load conditions at all major transmission and distribution locations within their service territory. ISO Advisory Warnings are also noted and logged.

Customer service representatives notice the forecasts predict a continuation of the heat wave through the end of the week. Internal supplemental forecasts identify a higher-than-acceptable potential for critical peak cost increases. In addition, data monitoring activities indicate that certain feeders are approaching threshold conditions that might lead to unacceptable voltage and other reliability problems. As a result, tree trimming and maintenance crews were redirected to accelerate scheduled work on the most severely impacted areas.

10:15 a.m., Friday, July 1, 2016 While reviewing the daily operating reports, customer service representatives confirm ISO critical peak advisories for their Southern Central Valley region and verify that these alerts are broadcast through their communication provider to all PCT and AutoDR site in the targeted portion of their service area. They also confirm that the alerts are posted to the utility Web site, reported in a banner in local newspapers, and distributed to targeted critical customer lists by email.

11:01 a.m., Friday, July 1, 2016 Critical peak price alerts for today automatically generate a series of

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computerized action plans that target the most critical substations and feeders for heightened monitoring. Action plans also identify and recommend customized dispatch strategies by substation and feeder locations to account for the potential duration and intensity of critical peak conditions.

Operators carefully review the action plans and modify the recommended strategies to reflect more current information regarding distribution and other system maintenance activity.

The detail in the preceding ''vision'' has a tendency to mask the two elements fundamental to future demand response and grid management activities; information and smart appliances.

Information tells you where you've been, where you are, and where your journey might take you. Advanced metering and SCADA are the keys to better information.

Smart appliances provide customers with the control they will need to more easily respond to price. By most standards, this vision understates what is truly possible. Embedded controls in air conditioners, pool pumps, water heaters, and other devices installed during manufacturing can reduce demand response implementation costs to just a few dollars per kilowatt – a clear cost-effective option for any utility system. Embedded, standardized interfaces to commercial and industrial buildings are even more cost effective.■

Endnote:

1. After the regulators adopted the PCT standards, many vendors and providers of automation services realized that the same price and reliability signals used to activate a PCT could also be used to control other residential as well as commercial facility loads. The CPP tariff provided a substantial economic incentive for controlling other facility loads in addition to the PCT-controlled HVAC systems.

❖ *M E E T I N G S   O F   I N T E R E S T* ❖

Conference	*Date*	*Place*	*Sponsor*	*Contact*
2nd Emerging Europe Energy Summit	Nov. 9–10	Vienna	IBP Publishing and Conferences	http://www.doingbusiness.ro/eees2006/summit.php?id_menu=1
China, India & the United States: Competition for Energy Resources	Nov. 19–21	Abu Dhabi	Emirates Center for Strategic Studies and Research	www.ecssr.ae
Renewable Energy Marketing Conference	Dec. 3–6	San Francisco	Smart Power	http://www.renewableenergymarketing.net
9th IASTED International Conference on Power & Energy Systems	Jan. 3–4, 2007	Clearwater, FL	IASTED	http://www.iasted.com/conferences/2007/florida/pes.htm
2nd International Conference on Underground Coal Gasification	Feb. 7	London	UCG Partnership Ltd.	http://www.ucgp.com
Middle East Electricity 2007	Feb. 11–14	Dubai	IIR Exhibitions	http://www.middleeastelectricity.com
Fundamentals of Energy & Electric Power Futures, Options & Derivatives	Feb. 20–21	San Diego	PGS Energy Training	http://www.pgsenergy.com/D201.html
International Power Summit 2007	Feb. 22–25	Prague	VIB Events	http://www.internationalpowersummit.com