U.S. DEPARTMENT OF ENERGY

Electricity Delivery & Energy Reliability

American Recovery and Reinvestment Act of 2009

Automated Demand Response Benefits California Utilities and Commercial & Industrial Customers

Smart Grid Investment Grant Program Recipient Deliverable

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RECOVERY ACT SMART GRID PROGRAMS

1. Summary

Idaho Power Company (IPC) developed a Renewables Integration Tool (RIT) that enables grid operators to use wind energy more cost-effectively to serve electricity customers in Idaho and Oregon. The tool was developed under a Smart Grid Investment Grant (SGIG) project that invested in new technologies, tools, and techniques for electric transmission, distribution, advanced metering infrastructure, and customer systems. RIT, a series of models and databases for forecasting weather conditions and the availability of wind energy resources, is now fully operational.

Under the American Recovery and Reinvestment Act of 2009, the U.S. Department of Energy and the electricity industry have jointly invested over $7.9 billion in 99 cost-shared Smart Grid Investment Grant projects to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an unprecedented level of data on smart grid and customer

At any given time, wind power can provide up to 35% of IPC's system needs. However, variability in the wind can cause grid operators to make rapid adjustments and bring non-wind resources on- and off-line depending on weather conditions. Improvements in wind forecasting tools can enhance the value of wind energy and lower grid integration and operations costs. Table 1 summarizes key results from IPC's application of the RIT wind forecasting tool.

Table 1. Summary of Key Wind Forecasting Tool Results for IPC		
Forecasting Improvements	i.	RIT is now a normal part of daily operational practices. An analysis of three months of data from the first quarter of 2014 showed the **RIT was 26%–32% more accurate than the forecasting methods previously used by IPC**.
	ii.	Forecast accuracy is due in part to increased data on wind speed and direction now being collected and analyzed from weather stations located at five of the major wind parks.
Financial Benefits	iii.	IPC estimates that **improvements in forecasting accuracy saved about $287,000** over the three-month study period, or about $96,000 a month.
Lessons Learned and Future Plans	iv.	**More and better weather data is still needed to support advanced forecasting tools**. IPC plans to expand data collection to more wind parks, and include weather and operational data requirements in new power purchase agreements for wind energy resources.
	v.	Although RIT is a customized software platform, **utilities interested in developing comparable wind forecasting capabilities could use RIT as a template**. However, weather data, wind turbine performance information, and statistical algorithms would have to be created to suit local conditions.

2. Introduction

IPC serves about 512,000 customers in southern Idaho and eastern Oregon. IPC's generation mix relies heavily on coal and hydroelectricity for base load generation and natural gas for meeting peak demands. However, wind power is a valuable contributor and at any given time can provide up to 35% of IPC's electricity generation, depending on weather and system conditions. In 2013 wind provided about 10% of the electricity IPC delivered to its customers. Figure 1 shows a map of the IPC service territory, which includes mountainous terrain and areas with high-quality wind resources.

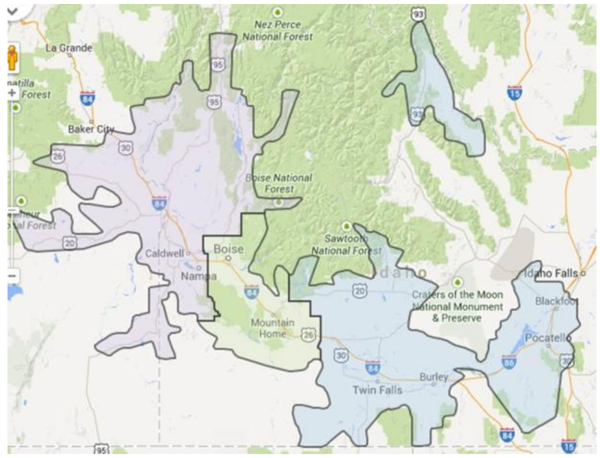

Figure 1. IPC's Service Territory

Because of the high potential for wind integration, the Renewables Integration Tool (RIT) was a key outcome of IPC's larger SGIG project, which also installed transmission line monitors, phasor measurement units, distribution automation equipment, smart meters, communications networks, and web portals and time-based rate programs for customers. The total project budget is about $98.2 million, including $47 million in funding from the U.S. Department of Energy under the American Recovery and Reinvestment Act of 2009.

IPC has recently seen a large growth of available wind power capacity that is expected to continue (see Figure 2). Total wind capacity for IPC is now approximately 700 megawatts (MW). However, a major challenge for grid planners and operators in using wind resources is the inherent variability and uncertainty of wind resources. The newly developed RIT provides a forecasting tool to more accurately predict the hourly level of wind energy generation IPC can procure from energy suppliers.

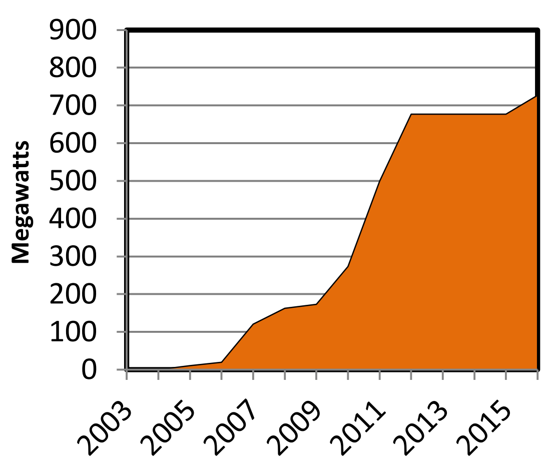

Figure 2. Growth in IPC's Wind Generation Capacity, 2004-2016

IPC's grid operators are now relying on RIT to determine how much wind will be part of the hourly and daily generation mix and what types of other resources—such as quick-start gas-fired units or demand response—will be needed should wind conditions change during the day, as they typically do. RIT forecasting is saving costs and improving operational practices for IPC and helping integrate wind power more efficiently and cost effectively.

Figure 3 shows how the availability of wind energy varies over a two-day period, which requires grid operators to increase or decrease other power supplies to keep overall system generation in line with customer electricity demand (system load). IPC found that available wind power is typically low or moderate in the afternoon and evening, when customer demand is typically peaking. Improved forecasting tools allow IPC to better predict the timing and amount of wind energy resource availability, which reduces the uncertainty associated with wind energy supplies and therefore allows operators to plan for and use other resources more efficiently to lower costs.

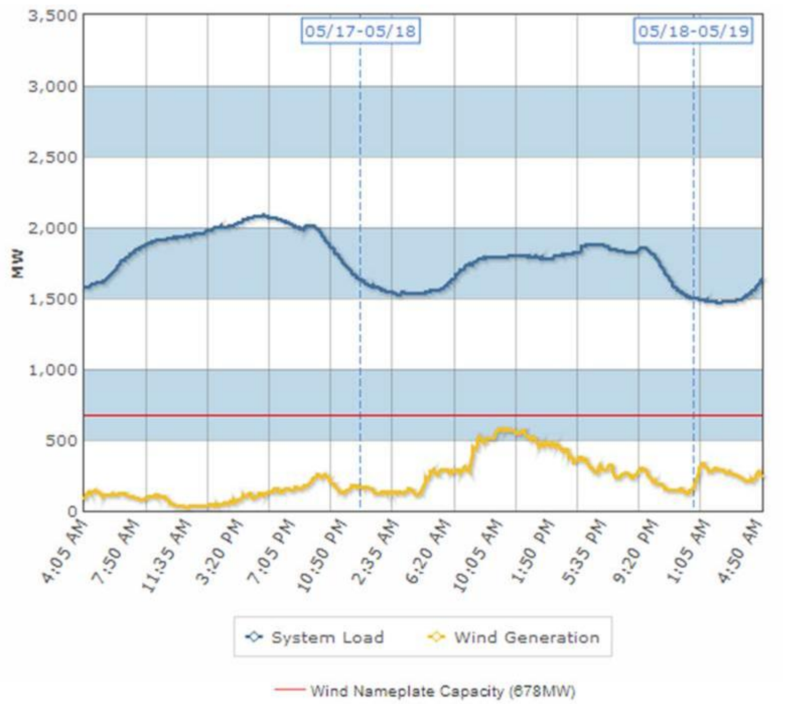

Figure 3. IPC system load and wind generation during a two-day period in May 2014

3. Improvements in Forecasting Wind Energy Resources

IPC determined it would need a customized set of wind forecast models and databases when it found no commercial products that offered the needed level of accuracy. IPC's Power Supply Planning Department had previously developed an in-house wind-generation forecast that relied on rudimentary National Weather Service data and basic rating curves for wind turbine performance. While this system showed potential, further research and development was needed to make it a more useful operational tool.

The goal was to address three wind forecast intervals: within one hour, hourly, and day ahead. IPC investigated a number of approaches, including a forecasting tool used by the Bonneville Power Administration. IPC eventually identified a set of weather forecasting models and datasets developed by the University of Arizona that was used and tailored to develop RIT for IPC's specific needs. RIT uses several weather models. The primary forecasting model for short-term forecasts runs four times a day and makes wind predictions 72 hours into the future. A second model—run once every day, Monday through Friday—makes predictions 180 hours into the future and is the primary forecast model for time frames beyond 72 hours.

RIT uses models that forecast power requirements based on weather data from meteorological towers located in multiple sites in five major wind parks, and from various public meteorological sites. The wind parks are geographically dispersed across about 300 miles of hilly terrain. RIT includes analysis and mapping tools that can graphically show wind speeds at 10 meters and 80 meters above the ground, abrupt changes in wind directions, and other important weather parameters.

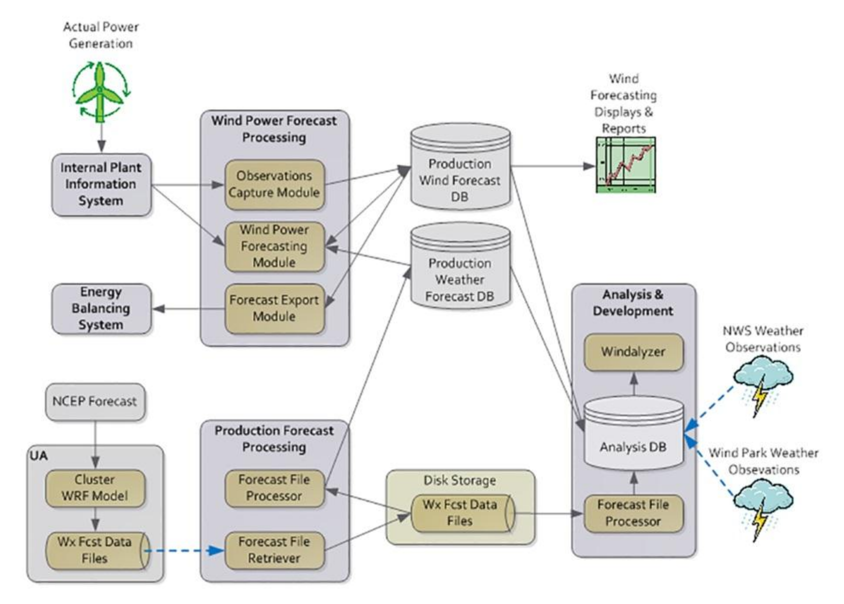

Figure 4. IPC's Renewables Integration Tool for Wind Energy Forecasting

Figure 4 is a diagram of the RIT system and shows the various modules and components. IPC has measured RIT's improvement in forecast accuracy. One of the metrics for measuring forecast accuracy is the mean-absolute-hourly-error (MAE), which is the sum of absolute value of the observed amount of hourly wind generation, minus the forecasted amount, and divided by the total number of hours in the forecasting period. Using RIT, grid operators have seen an approximate 40% reduction in MAE for the short-term wind forecasts.

IPC conducted a detailed analysis covering a three-month period from February to April 2014 to compare forecasting accuracy using three different methods, shown in Table 2.

Table 2. Forecasting Accuracy from February – April 2014	
Method	**Average Hourly Error Rate**
The assumption from IPC's previous forecasting method that 33% of total installed wind capacity would be available	MAE of 136 MWH
A rolling 3-day average of actual historical wind generation	MAE of 149 MWH
RIT model forecasting	MAE of 100 MWH

The actual average hourly amount of energy from wind during this time period was 233 MWH. **The analysis demonstrates a 26% to 33% improvement in forecasting accuracy over three months using the RIT compared with the other two methods**. However, IPC still sees a wide variability of energy received in any given hour due to the difficulty of predicting hourly wind characteristics. As a result, grid operators still confront significant levels of uncertainty due to unexpected variations in wind generation. While RIT creates higher confidence in wind generation forecasts, this confidence can vary from day-to-day as well as from hour-to hour.

Sometimes IPC is highly confident of the accuracy of its wind forecast due to previous experiences with comparable weather conditions; however, in other instances more unpredictable weather cause confidence levels to be much lower. **Further refinements and more experience are needed for IPC to fully understand the contributions and limits of RIT in improving the grid integration of wind**.

4. Financial Benefits from Improved Wind Forecasting Accuracy

IPC conservatively estimates that RIT enables a 25% improvement in forecast accuracy when making operational decisions on a daily basis—representing the low end of accuracy improvements demonstrated in IPC's three-month analysis of forecast improvements. To estimate the financial benefits from this improved forecasting accuracy, IPC used a conservative estimate of $15 per megawatt (MW)-based on analysis of many economic and energy variables including hourly loads, day-ahead market prices, real-time market prices, coal plant dispatch prices, gas plant dispatch prices, hydro generation prices, minimum loading on generators, regulating margins, and required reserves. Better forecast accuracy produces operational savings due to reductions in the amount of regulating reserves that IPC grid operators need to have available to meet variations in wind generation.

As a result, **IPC estimates that using the RIT saved about $287,000 for the three-month period analyzed**. This translates into cost savings of about $96,000 per month from using the RIT as compared to the two other forecasting methods that were used before RIT was developed. Over time, these savings outweigh the costs of developing, maintaining, and upgrading the RIT.

More accurate forecasts can also help grid operators to anticipate high wind conditions that can damage equipment. To prevent damage, wind turbines are taken offline (referred to as "cutouts") during these conditions. Predicting cutouts in advance helps operators manage turbine maintenance and downtimes by more efficiently bringing other resources online to meet demand.

5. Lessons Learned and Future Plans

IPC addressed several challenges in developing wind energy forecasting capabilities and with their integration into electric power system planning and operations.

Getting timely and accurate data on wind speeds and wind generation were early problems that are still being addressed. For example, IPC's power purchase agreements with wind power developers were written before the needs for more accurate wind forecasts were known to be needed. Some of the agreements lacked provisions for expanded data collection. Going forward, IPC wind power purchase agreements will need to take data collection requirements into account.

There is also a lack of meteorological towers in or near all of the wind parks serving IPC, raising difficulties with correlating wind speeds to power generation. For example, because of intermittent updrafts and downdrafts in hilly areas, acquiring accurate wind measurements and processing the data in real time to produce accurate wind generation forecasts is a continuing challenge for meteorologists and wind modelers. Managing large volumes of weather, wind turbine performance, and other system-related data on electricity demand and power supplies requires continuing efforts to develop algorithms that can process and analyze the data to extract the most relevant data sets for operations and decision making. As a result, improvements in data analytics remain an important priority for the future. Figure 5 provides an example of RIT's current data analytical capabilities.

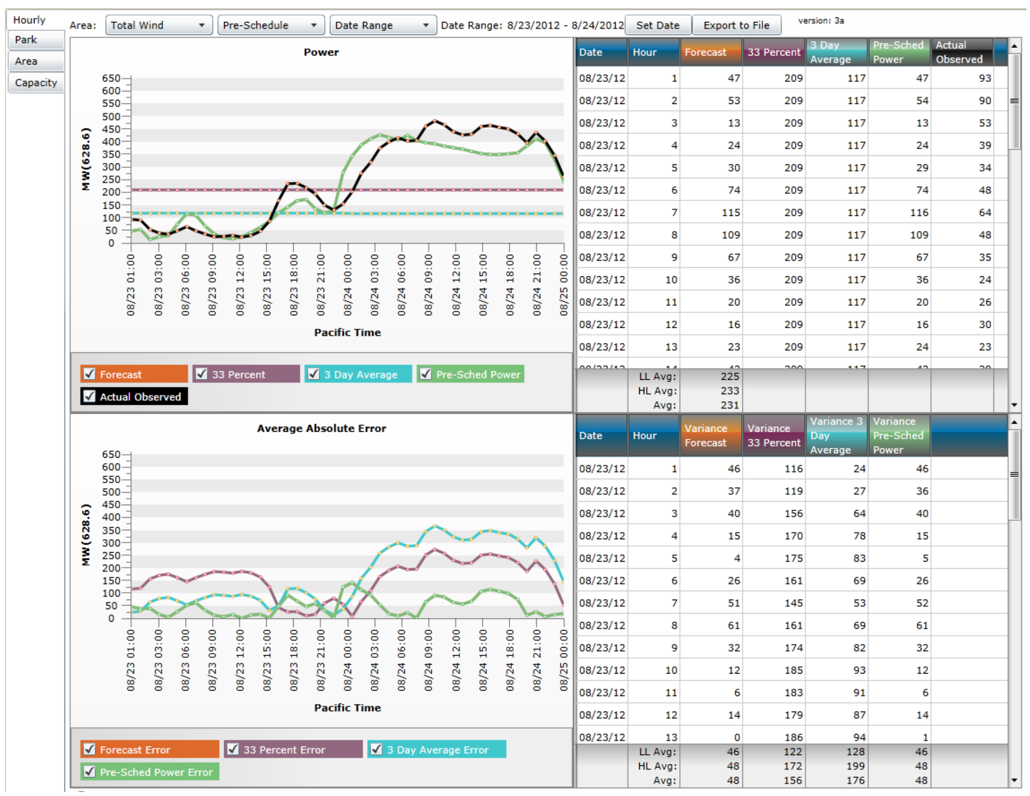

Figure 5. RIT Screen-shot of the Pre-schedule Forecast Comparing New and Previous Forecasts in the Top Portion of the Display and Hourly Error Values in the Bottom Portion.

In developing RIT, IPC assembled technical teams of analysts and data specialists with expertise in programming, electric system planning and operations, and meteorology. A key factor of project success was getting the electric system planners and operators involved in the development efforts from the earliest stages. This enabled the development teams to focus on user friendliness and visually appealing data displays.

The RIT is a customized software platform that is specific for IPC's service territory. Other utilities interested in developing comparable wind forecasting capabilities could use the RIT platform as a template but weather data, turbine performance statistics, data on system supply and demand conditions, and statistical models would have to be created for the specific locations where they will be applied.

Going forward, IPC plans to expand RIT by incorporating more weather data from additional wind parks. One of the priorities involves refinements to the models that forecast high-wind speed conditions and cut-outs. IPC also plans to detect approaching changes in wind speeds from weather observations "upstream" of the wind parks and create early-warning forecasts, particularly for thunderstorms which can disrupt the availability of wind resources for power generation. In addition, IPC plans to refine its databases and data flows on wind turbine performance to improve understanding of wind power capacities.

6. Where to Find More Information

To learn more about national efforts to modernize the electric grid, visit the Office of Electricity Delivery and Energy Reliability's website and www.smartgrid.gov. DOE has published several reports that contain findings on topics similar to those addressed in IPC's SGIG project and this case study. Web links to these reports are listed in Table 3.

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	iii.	SGIG Case Studies
Smart Grid Demonstration Program Reports	**iv.**	Technology Solutions for Wind Integration in ERCOT, September 2013
	v.	Dynamic Line rating Project, August 2013
Other Recent Publications	**i.**	Smart Meter Investments Yield Positive Results in Maine, January 2014
	ii.	Smart Meter Investments Benefit Rural Customers in Three Southern States, March 2014
	iii.	Control Center and Data Management Improvements Modernize Bulk Power Operations in Georgia, August 2014
	iv.	Using Smart grid Technologies to Modernize Distribution Infrastructure in New York, August 2014
Transmission and Synchrophasor Technologies	**v.**	Synchrophasor Technologies and their Deployment in Recovery Act Smart Grid Projects, August 2013
	vi.	Model Validation Using Synchrophasors NASPI Technical Workshop, October 2013
	vii.	Phasor Tools Visualization NASPI Technical Workshop, June 2012
	viii.	Synchrophasor Technology and Renewables Integration NASPI Workshop, June 2012

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1. Summary

Honeywell's Smart Grid Investment Grant (SGIG) project demonstrates utility-scale performance of a hardware/software platform for automated demand response (ADR). This project stands apart from the other SGIG projects in that it focused both on the development of an ADR hardware/software platform to facilitate demand response and on recruiting and educating ADR customers to participate in energy saving programs sponsored by utilities. The project uniquely targeted larger commercial, industrial, and institutional customers (with an average demand of 200 kilowatts [kW] or more) rather than residential customers.

Under the American Recovery and Reinvestment Act of 2009, the U.S. Department of Energy and the electricity industry have jointly invested over $7.9 billion in 99 cost-shared Smart Grid Investment Grant projects to modernize the electric grid, strengthen cybersecurity, improve interoperability, and collect an

Honeywell partnered with three California utilities—Pacific Gas and Electric Company (PG&E), San Diego Gas and Electric Company (SDG&E), and Southern California Edison (SCE)—to help target customers and make the project a success. Honeywell developed the ADR system to help participating customers automatically respond to utility notifications of demand response events, curtail demand of pre-selected equipment, and save money from lower off-peak rates and utility incentive payments.

Once installed at the customer site, the Honeywell ADR system communicates with the customer's own energy management system (EMS) to implement equipment curtailments, which the customer pre-selects based on their own priorities. Customers typically choose to curtail non-essential lighting and elevator banks, and equipment such as pumps, motors, compressors, and refrigeration systems, whose operations can be delayed without significant losses.

Honeywell found that customers often were not aware of their utility's demand response programs or the magnitude of potential cost savings. Many also did not yet have the EMS capabilities to automate curtailment of specific equipment in response to the utility's demand response notifications. This project helped demonstrate the benefits of new demand response capabilities that can support wider adoption once ADR technologies become more cost-effective. Table 1 is a summary of the key results.

Table 1. Summary of Key Results		
Energy Savings, Demand Reductions, and Financial Benefits	i. ii.	Savings were substantial for participating customers. One food distributor **reduced its monthly electricity bills from $50,000 to $35,000** and its monthly power consumption by 25%. A manufacturing facility in Torrance, California received **more than $75,000 in bill credits** for its participation in 11 demand response events in 2012 and 2013.
Customer Interest and Suitability	iii. iv.	Honeywell enrolled 61 customers, involving 282 sites, with control of more than **49 megawatts of curtailable electricity demand**. **Water districts** that operate large pumping stations and have flexibility to shift demand from on- to off-peak periods, **are well-suited for ADR** and were found to be among the most ideal customers.
Lessons Learned and Future Plans	v. vi.	Honeywell **reduced the cost of the ADR gateway by 50% but further reductions are needed** to improve cost-effectiveness and enable wider adoption. Because each customer has unique characteristics, **customization is a major cost driver**. Efforts are needed to standardize systems and implementation requirements.

2. Introduction

Honeywell is a Fortune 100 company that develops and manufactures a wide range of technologies and tools, and provides supplemental services for clean energy generation and energy efficiency. For its SGIG project, Honeywell developed an ADR system targeted for large electricity customers (greater than 200 kilowatts of connected load) to facilitate their participation in demand response markets in California. Honeywell worked with PG&E, SDG&E, and SCE in California to implement the project. Figure 1 shows a map of Honeywell's ADR installations in California.

Demand response is an important tool for improving the delivery of electricity because it reduces demand during peak periods and helps grid operators keep demand and supply in balance. Peak demand is a major cost driver for the delivery of electricity as it requires utilities to build power plants that may be used for only 10% of the time, or less. Peak demand reductions reduce electricity costs and improve utilization of grid assets such as power lines, substations, and power plants.

Honeywell's ADR system, which is powered by a Demand Response Automation Server (DRAS), involves commercially available technologies customized for customers so they can implement their own load control strategies in response to notification or price signals from their utility. The system is designed to interface with and augment the customer's energy management systems. ADR components include hardware and software for obtaining price signals and notifications from utilities through an ADR gateway. They also include systems for monitoring and controlling building and factory loads such as lighting, heating, cooling, air handling, motors, and refrigeration.

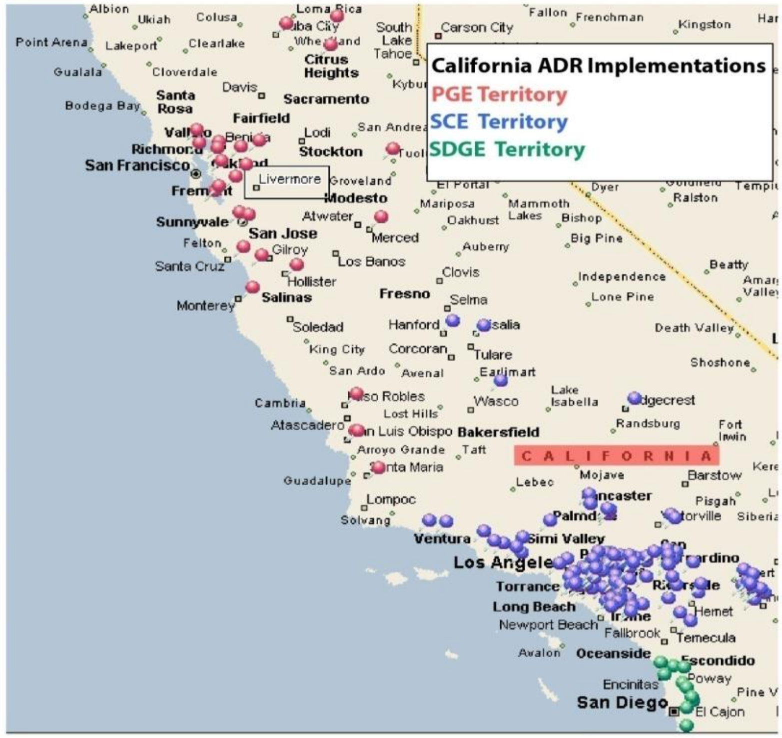

Figure 1. Map of Honeywell ADR installations in California.

Honeywell's approach to ADR involves working with local utilities to recruit commercial and industrial customers to participate, conducting audits to advise customers on load control strategies, and installing and commissioning the systems.

Figure 2 shows the ADR's step-by-step process. Utilities start by sending out notification signals for upcoming critical peak events. This signal is received and processed by the demand response automation server (DRAS), which then signals a controller located on the customer's premise connected to the onsite EMS. The system uses OpenADR, an open, industry-standard communication protocol, to pass messages between the DRAS, controller and EMS.

Once a signal is received, the EMS uses a priority list of pre-selected curtailments that were identified by the participants in accordance with their own needs. Typical curtailments include non-essential lighting and elevator banks, and certain equipment such as pumps, motors, compressors, and refrigeration systems, whose operations can be delayed without noticeable disruption.

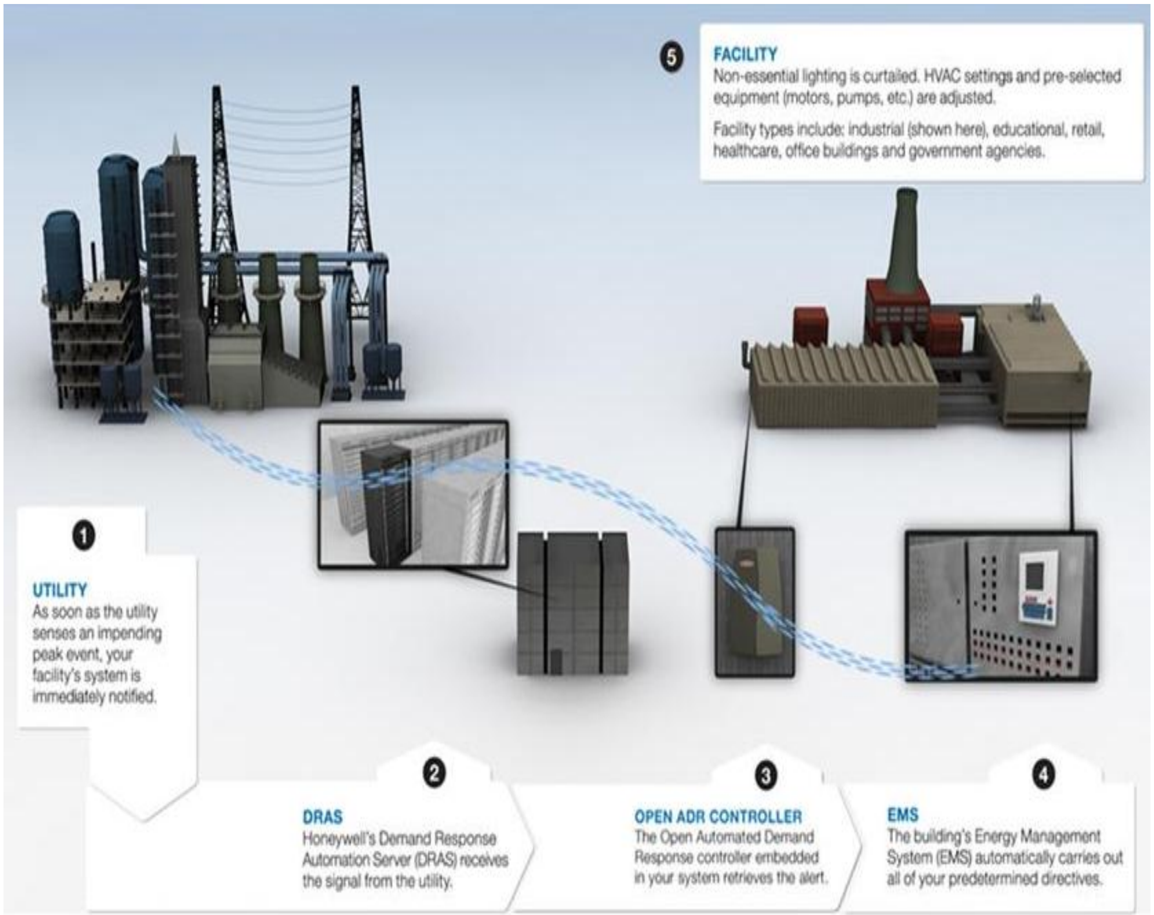

Figure 2. Overview of Honeywell's ADR system.

Honeywell found that many customers did not have an EMS or an EMS with connected loads. In these instances, Honeywell helped customize the EMS software to enable more flexible and effective responses to load management signals from the utilities. For example, for Jet Propulsion Lab (JPL), a participating customer with 155 buildings, Honeywell added an air handler control feature that can be adjusted by JPL to achieve 10% to 50% curtailment during demand response events.

3. Energy Savings, Demand Reductions, and Financial Benefits

The energy savings, demand reductions, and financial benefits from Honeywell's ADR system depends on a variety of customer-specific factors including curtailment strategies, the amount of load customers choose to place under control, and the time-based rate or incentive program in which they participate. The basic methodology to determine energy savings involves comparing customer consumption levels during critical peak events with baseline levels. The mechanics of calculating baselines and energy and load impacts vary by program.

Honeywell found that many customers were not aware of demand response programs and the associated benefits and costs. For example, customers did not know the benefits of participating in time-based rate programs, the steps needed to curtail demand, and other financial benefits such as incentive payments, lower rates during off-peak periods, and lower bills. Many customers also did not know that electricity production and delivery costs fluctuate during the day and that by reducing demand during the most costly times of the day, they could reduce the utility's electricity costs.

Honeywell's ADR project was successful in helping customers reduce their electricity costs. Coastal Pacific Foods Distributors (CPFD) was able to reduce its monthly energy bills from $50,000 to $35,000 and cut its electricity usage by more than 25%. During events, CPFD can curtail demand by more than 110 kilowatts. At the same time, the EMS provides CPFD with the ability to act in a more efficient manner by controlling air temperature and lighting during non-event days. Honeywell's facility in Torrance, California, also participated in the program, and has received more than $75,000 in bill credits for its participation in 11 demand response events in 2012 and 2013.

The Honeywell ADR system also proved effective in reducing peak demand. Figure 3 shows electricity consumption curves aggregated across a group of participating customers for an average critical peak event day in the winter of 2012. The figure shows the amount of demand curtailment realized from the use of Honeywell's ADR system compared to the winter baseline.

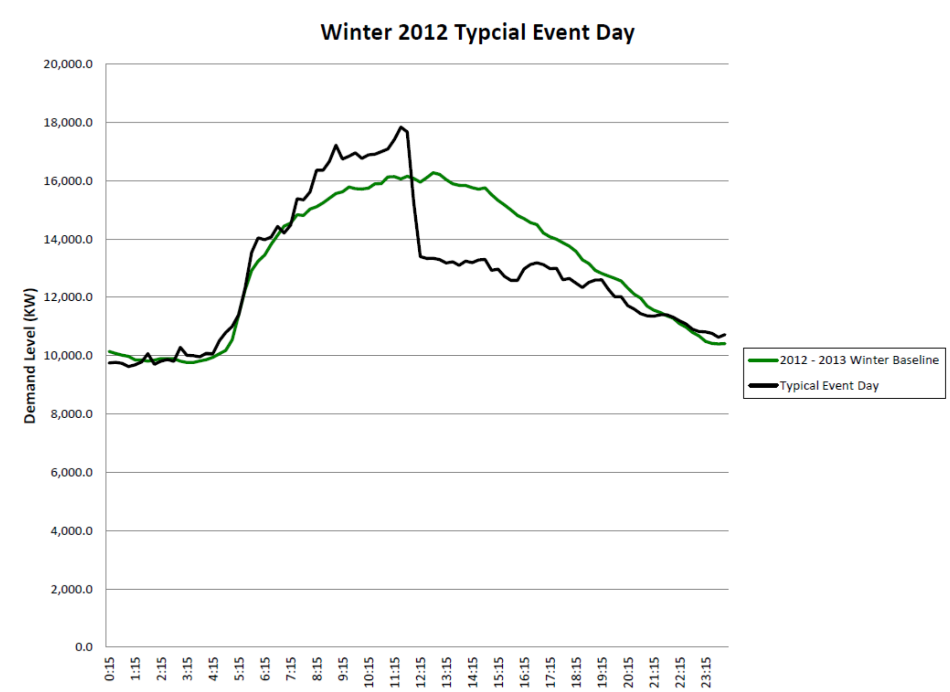

Figure 3. Customer Electricity Demand Curves from Winter, 2012.

4. Customer Interest and Acceptance

Honeywell targeted commercial and industrial customers whose average loads exceed 200 kW. As shown in Table 2, Honeywell currently has 61 unique customers and a total of 282 sites. The total amount of curtailable load is 49.8 MW.

With SGIG funding and utility financial incentives, Honeywell was able to provide its ADR system at low to no cost for most customers. SCE and PG&E, for example, co-financed deployment by paying $300 and $200 respectively per kilowatt of curtailable load. Honeywell's implementation costs, as of the second quarter of 2014, were about $400 per kilowatt of curtailable load. SGIG funds made up the $100-$200 difference in costs between the $200-S300 of utility incentives and Honeywell's costs of $400. The majority of the costs were for EMS upgrades. Honeywell is researching a number of different technologies that could further reduce implementation costs.

Table 2. Numbers and Types of Participating Customers in ADR in California.*

Customer Type	Number of Customers	Number of Sites	Total MW
Commercial	14	23	2.6
Education	1	1	0.6
Industrial	35	39	26.4
Municipal	9	102	17.5
Retail	2	117	2.7
Total	**61**	**282**	**49.8**

*As of August 6, 2014

Customers can use the Honeywell ADR system to improve their everyday energy efficiency, not only on days when peak events are called. For instance, customers can elect to curtail non-essential equipment on non-event days to save energy and money. Customers can also choose their own energy savings and curtailment strategies by selecting from two levels of participation: high- or medium-level. They can also opt-out of events.

Honeywell found that most customers have developed their own energy management priorities and strategies. For example, many commercial customers value heating and cooling highly and are not interested in total curtailments. However, they are willing to change set-points, turn-off some chillers, and change air handler speeds. Figure 4 is a photo of the ADR selection screen at a customer's site.

Water districts frequently participate in demand response events and work with third-party, load aggregators to participate in financially attractive capacity bidding programs. Water districts can manage their water supplies and turn off pumps for up to two hours during peak periods, without affecting operations and services. Honeywell found water districts to be among the most attractive candidates for ADR.

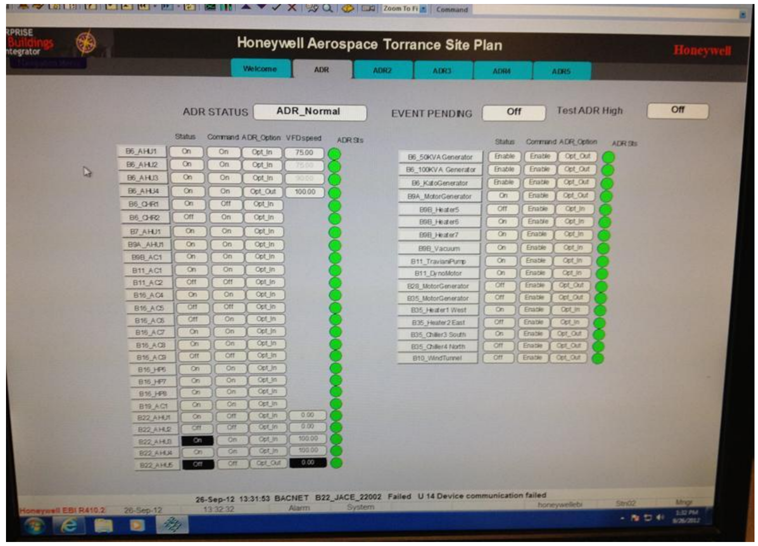

Figure 4. ADR selection screen.

5. Lessons Learned

During the recruitment phase, Honeywell found that ideal customers fall into two categories: (1) customers whose operations make it possible for them to curtail demand without affecting performance, and (2) customers whose systems are easy to automate for demand response. Water districts are considered among the most ideal because they can change water pumping schedules and curtail demand without significant disruptions in services. Certain commercial customers and retailers that already have energy management systems can be integrated into ADR, but they may have limited ability to curtail demand because building occupants cannot easily dim lights or reduce heating or cooling without affecting their businesses.

Manufacturing and industrial customers present some unique challenges for ADR, because they often face complex decisions about trade-offs in productivity and performance in exchange for demand curtailment incentives. For example, one manufacturer is on a real-time pricing rate and rates can increase significantly when temperatures exceed 95^{o}F. Before the ADR equipment was installed, this customer would have to curtail all demand when temperatures went over 95^{o}F, basically shutting down operations, to save money on the rate. As a result, Honeywell customized the EMS to automatically show the tradeoff between production profits and electricity costs so the customer could make real-time decisions about whether and how much to curtail demand. As a result of using Honeywell's ADR system, this customer can now optimize their operations over the course of the day.

About 10% of the targeted customers had an operating EMS that controlled connected equipment. For the 90% without EMS, Honeywell incurred the cost and installed one. For some of the customers who had EMS, Honeywell found they needed to install system upgrades to include equipment not connected to the EMS that the customer controlled using wireless remote control equipment. While Honeywell was able to expand participation by helping customers with EMS, this step caused significant increases in Honeywell's costs.

6. Future Plans

Honeywell's future plans include activities aimed at lowering system development and implementation costs. Going forward, the company plans to focus marketing efforts on the most attractive customers for ADR systems, including water pumping facilities, big box retailers, and large manufacturing plants. Honeywell also plans to find new ways to lower hardware and software costs. As part of the SGIG project, Honeywell was able to reduce the cost of the ADR gateway (Figure 5) by 50%, and believe savings can be achieved for other system components as well.

Figure 5. Honeywell's ADR Controller.

Honeywell would also like to expand capabilities to make the system attractive to a broader array of customers. For example, based on its SGIG project experience, Honeywell recognized the potential to develop real-time feedback for performance monitoring. This led to the development of the new OpenADR 2.0b protocol.

Most of the benefits of Honeywell's SGIG project were realized by the three utilities and all of the participating customers. However, without DOE funding to make up the difference between Honeywell's costs and the incentive payments from the utilities, they would not have been able to participate. Reducing system costs are a top priority for future ADR development.

7. Where to Find More Information

To learn more about national efforts to modernize the electric grid, visit the Office of Electricity Delivery and Energy Reliability's **website** and **www.smartgrid.gov**. DOE has published several reports that contain findings on topics similar to those addressed in Honeywell's SGIG project and this case study. Web links to these reports are listed in Table 3.

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SGIG Consumer Behavior Studies	iv.	**SGIG CBS Project Descriptions, and Interim and Final Evaluation Reports**
	v.	**Analysis of Customer Enrollment Patterns in Time-Based Rate Programs – Initial Results from the SGIG Consumer Behavior Studies, July 2013**
	vi.	**SGIG Consumer Behavior Study Analysis: Summary of the Utility Studies, June 2013**
	vii.	**Quantifying the Impacts of Time-Based Rates, Enabling Technologies, and other Treatments in Consumer Behavior Studies: Guidelines and Protocols, July 2013**
	viii.	**Lessons Learned from SGIG CBS Projects**
Other Recent Publications	**ix.**	**Smart Meter Investments Yield Positive Results in Maine, January 2014**
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