Practitioner Perspectives™

16th PLMA Award-Winning Load Management Initiatives

A Compendium of Industry Viewpoints

Edited by
PLMA Award Planning Group
November 2019

PLMA (Peak Load Management Alliance) is a non-profit organization founded in 1999 as the Voice of Load Management Practitioners. PLMA seeks to advance practical applications of dynamic load management and distributed energy resources by providing a forum where members educate each other and explore innovative approaches to program delivery, pricing constructs, and technology adoption. For two decades, PLMA conferences, educational programs and networking opportunities have brought member organizations together to develop, implement and share proven practices in a peer-to-peer network – offering load management leadership for the energy industry. Learn more at www.peakload.org.

PLMA Award Planning Group

Co-chaired by Michael Smith of National Grid, Laurie Duhan of Baltimore Gas and Electric, and Dain Nestel of ecobee, this Group oversees the nominations and judging process for PLMA's annual awards presentation. Any staff from a PLMA member organization may join this Group. Details at www.peakload.org/group-overview.

Michael Smith
National Grid

Laurie Duhan
Baltimore Gas and Electric

Dain Nestel
ecobee

PLMA™ Load Management Leadership AWARDS

Thank you to 16th PLMA Award Program Judges (in alphabetical order)

- Rich Barone, Hawaiian Electric
- Nick Bengtson, CLEAResult
- Ryan Brager, Eaton
- Matt Carlson, Aquanta
- Erika Diamond, EnergyHub
- Audra Drazga, Energy Central
- Laurie Duhan, BGE
- Troy Eichenberger, TVA
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PLMA Practitioner Perspectives: 16th PLMA Award-Winning Load Management Initiatives
A Compendium of Industry Viewpoints

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PLMA (Peak Load Management Alliance) announced eight winners of its 16th PLMA Awards in April 2019. The Awards were presented during the 39th PLMA Conference in Minneapolis, Minnesota. Those recognized for outstanding load management programs, initiatives, and achievements in calendar year 2018 were:

Program Pacesetters

- Pacific Gas and Electric Company and Olivine for Excess Supply Demand Response Program
- Portland General Electric and Enbala for Distributed Flexibility at Scale
- Indiana Michigan Power and Tendril for Residential Integrated Demand Side Management Approach

Thought Leaders

- Efficiency Vermont, Green Mountain Power, and Dynamic Organics for Flexible Load Management
- Eversource Energy for Commercial & Industrial Active-Demand Management Demonstration

Technology Pioneers

- Bonneville Power Administration, Portland General Electric, and Northwest Energy Efficiency Alliance for Water Heater Communications
- Rocky Mountain Power for Frequency Dispatch
- Viking Cold Solutions for Using Thermal Energy Storage as a Grid Asset

The 16th PLMA Awards recognize industry leaders who created, during calendar year 2018, innovative ideas, methods, programs, and technologies that manage end-use loads to meet peak load needs and support successful grid integration of distributed energy resources. Over the past 15 years, PLMA has presented over 74 awards to recipients who have included utilities, product/service providers, end-users, and individuals responsible for demand response efforts targeted to the residential, commercial, industrial, and agricultural customer markets.

The following are transcripts from web conversations with these industry leaders.

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Technology Pioneers

Bonneville Power Administration, Portland General Electric, and Northwest Energy Efficiency Alliance for Water Heater Communications

Presented August 1, 2019

A team from the Pacific Northwest spearheaded by three individuals – Tony Koch of the Bonneville Power Administration, Conrad Eustis of Portland General Electric, and Geoff Wickes of Northwest Energy Efficiency Alliance – advanced the testing of the new ANSI/CTA-2045 communications standard to connecting important energy storage assets – electric water heaters and heat pump water heaters. This collaboration and research proposes new economics that will have important impacts on Deamnd Response (DR) planning as well as understanding of how to validate and increase energy savings from a new generation of "connected" technologies. This project had a series of firsts:

- The largest smart water heater pilot ever implemented
- The first large demonstration of heat pump water heaters participating in DR events
- Eight utilities cooperating to implement the same event schedule
- Multiple DR events every day with over 600 events in 220 days
- Coordination with key water heater manufacturers to prove out communications and commands

Dialogue Transcript

Laurie Duhan: Today, Tony Koch of the Bonneville Power Administration and Conrad Eustis of Portland General Electric will discuss connected water heaters as a valuable demand response (DR) resource, which won PLMA's Technology Pioneer Award. Tony and Conrad, can you please introduce yourself and tell us a little bit about the program?

Tony Koch: This is Tony Koch with Bonneville Power Energy Efficiency, and I co-worked with Conrad on this project and we'll hear more about it. I sit in the Seattle office.

Conrad Eustis: And I'm Conrad Eustis, formerly Portland General Electric, now Principle at Reascend LLC, and I've been working on demand response activities since about 1993 but this project is, I would say, the highlight of my career.

Duhan: I just want to start off with the word 'smart' because that's used a lot these days, specifically, what do you mean by smart appliance?

Eustis: It's an appliance with electronic controls that can be connected to a remote location for the purpose of control and telemetry. But I would also add that the appliance should, if it's being controlled by the utility, ensure that customer needs are met before grid needs are met.

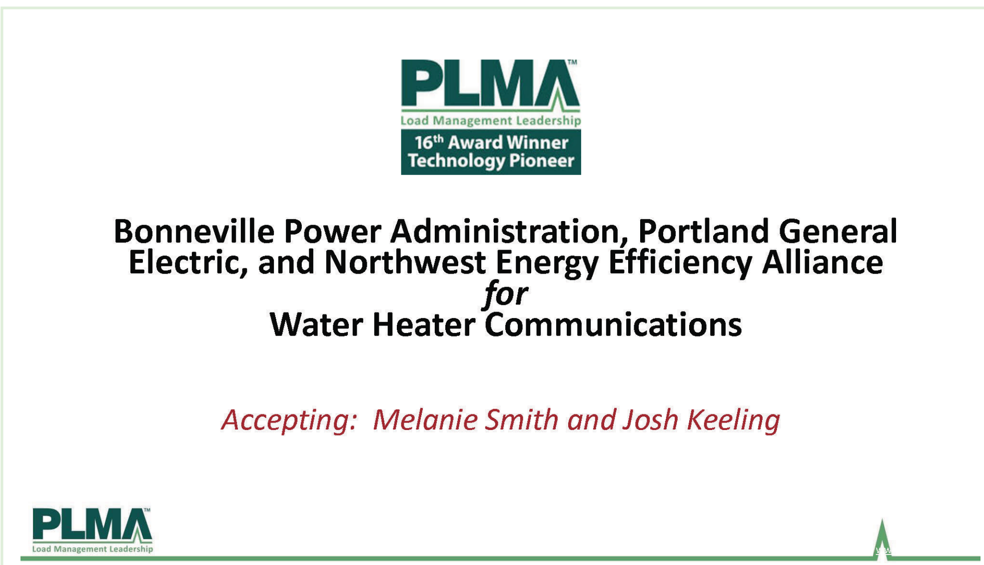
Duhan: How significant are the economic benefits of the smart water heater?

Eustis: The pilot estimated benefits in the states of Oregon and Washington, with a 95% saturation of CTA-2045 enabled electric water heaters, replaced naturally over their life cycle and also included new construction. Enrollment was lockdown in 2039 at 26% of all the tanks enrolled. Then the demand response benefits were compared to building a peaking plant with a net benefit of $230 million, and a benefit cost ratio of 2.6. If we extrapolate this to the U.S. market the net benefit would be over 3 billion.

Duhan: We have some pre-submitted questions. Joe Schmutzler with Transformative Wave wants to know if you'll be reviewing commercial and multifamily applications as well?

Koch: Not at this time. We didn't in this project, but I think it would be a good next step. But with that I think we want to do some prepared remarks from Conrad first and then we'll continue into the questions.

Eustis: I'll give a short overview of the pilot and the reasons for it and I appreciate everybody taking time to



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learn more about this pilot. PLMA, by definition, is concerned with reducing on-peak loads and our water heater demand response demonstration pilot did of course address peaks. But this pilot introduced a new paradigm change that will enable 24x7 demand response in a century where the industry will be transformed by generating electricity primarily from wind and solar. These poor capacity factor generation technologies will produce power that will exceed demand in thousands of hours per year. That's necessitating the need to curtail them or throw away electricity, and this is already happening in our area and in California. And there's two primary solutions to dealing with excess generation. The obvious one, of course, is battery storage, but the cheaper solution is loads that have the flexibility to shift some of their use to periods of excess generation.

This pilot demonstrated the economic potential and customer acceptance for smart, what I call alonetic appliances. Alonetic devices are a customer friendly ways to shift load at scale. And if you have some time search the word 'Alonetic'. The enabler of this new paradigm is a modular communication interface standard called ANSI/CTA-2045. We'll explain the technical details of the standard during the question period but in summary, CTA-2045 is a standardized port that allows the customer to insert a communication device into the appliance, and this device enables remote monitoring and control. This new standard is for appliances what USB is for computers and other electronic devices. The port can pass messages in any command language including the manufacturer's proprietary commands. But in this pilot the manufacturers supported the generic and optional CTA-2045 demand response commands like shed, grid emergency, load up and other such commands in the specification.

The CTA-2045 communication device used in this pilot was mailed to the customer by one of the eight participating utilities. The device listened to FM radio control signals to manage the water heater, but the communication device also had Wi-Fi and used the customer's Internet connection to pass us data on a minute-by-minute basis so we could calculate the impact benefits of our demand response events. You should note that the CTA communication device can be designed to use any communication, even multiple methods in one piece of hardware, as was done in our pilot. For example, the communication could be a smart meter manufacturer's mesh network chip, or it could be a 4G LTE chip, or any communication method that has yet to be invented or implemented. For example, 5G.

Let me pause for a moment because this concept is so critical for universal adoption and future optionality. Via the communication device plugged in, by the customer, the appliance can be controlled to support any business model by any communication method and via any command language. The standard port is future proof. In the middle of the pilot, for example, GE sold their heat pump water heaters and their manufacturing line to Bradford White and because our pilot had no dependence on GE's website or their portals for utilities, the sale had no impact on our pilot whatsoever.

The key to customer satisfaction is how the manufacturer programs the water heater to operate when it receives the generic DR commands. If the manufacturer's program, which of course has access to all of the manufacturer's sensors, as well as a history of the hot water use at this one water heater, determines that sufficient hot water is not available for the customer, then the curtailment request from the utility is ignored. Each DR request is an independent decision and curtailment can begin later in the event, once the hot water shortage is eliminated.

The pilot operated without customer notification, we implemented over 600 DR events in 220 days. At the end of the pilot, 80% of the customers responded that they were very satisfied. And based on a year of experience, 81% of customers responded they had run out of hot water only a couple times or even less. We tested both heat pump water heaters and resistance water heaters. The pilot had two nearly independent primary objectives. The first was to enroll customers, run hundreds of DR events, and we did that at all times of the day, then we evaluated the peak load reductions and the energy shifts we could achieve using the tanks.

The first objective was your standard DR pilot. But the bigger and more important part of the project was to create a market transformation plan that would cause all water heaters shipped to the Pacific Northwest to leave the factory with the CTA-2045 port. We determined the cost of this plan and finally determined the net benefits of implementing the plan based on the load reductions determined under the first objective. You should note that nobody, to my knowledge, has ever created a market transformation plan for demand response ready appliances before. You should think about the implications of market transformation to implement DR-ready appliances.

Most of you are very familiar with the issues associated with installing a control switch on a residential premise. In fact, this approach is increasingly difficult to make cost-effective.

CTA-2045 is a better approach than connecting to a vendor's server to control load seems attractive at first, but there are three major drawbacks to this approach. The market share of customers that buy the premium products that can be connected is relatively small, and often those customers are not the ones that would most benefit from DR incentives in the first place. Second, the costs to create vendor agreements and to maintain the application interface to the vendors will be considerable when you realize that there's going to be 40 major vendors that manufacture devices worth controlling. That cost is significant compared to the zero-cost option of using a standard port approach like USB. And finally, the customer experience will be different for each product in the home from a different vendor. A different process when you connect to the vendor's cloud, a separate control app for each device, even the control process might vary with each manufacturer.

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The CTA-2045 approach would solve all of these problems as appliances are replaced. And yes, it's going to take 20 years to replace most appliances and that may seem like a long time, but in 2040 as renewable energy approaches 100% in many markets, wouldn't you rather be trying to enroll all of the major loads for 100% of the customers using the same simple approach? Or would you rather be managing the application interfaces to 40 large companies, managing separate marketing campaigns and only have access to 25 to 40% of the customers that actually purchased the premium products with communication capability? Since the pilot ended, the persuasive economics of our project justified the Washington State Legislators to pass a law to require a CTA-2045 on all heat pump water heaters sold in Washington beginning January 1, 2021, and all electric resistance water heaters sold beginning January 1, 2022. PGE is working with other stakeholders to pass a similar law in Oregon. In lieu of a law, the option still exists to implement the market transformation plan in the report. Under this plan utilities would fund a process to pay manufacturers for the incremental costs of adding CTA-2045 on all water heaters shipped to Oregon. That's the high level summary and now we're ready for the rest of the questions.

Duhan: You talked a lot about this in relation to electricity and electric load and Tracey Dyke Redmond from Eversource was curious if you have a similar DR-enabled control equipment for gas water heaters?

Koch: No, I'm not aware of that. But manufacturers that build both electric and gas can easily migrate the electric tank technology to the gas but there's engineering and retooling. So there's an opportunity but there isn't anything available that we're aware of right now.

Duhan: How do you manage to ship only smart water heaters into the Pacific Northwest?

Eustis: Under the plan in the report NEEA, which is the Northwest Energy Efficiency Alliance, who in our region implements market transformation efforts, would pay the manufacturers the incremental cost per tank before they ship to Oregon and Washington. In other words, all of the tanks destined for Oregon, Washington would have the CTA-2045 feature and the manufacturers would get compensated for that incremental cost. This process would be adjusted each year as the total volume increased since the incremental costs per tank will decline with volume. And the process will continue, the process of providing the incremental cost, until state and or federal codes kick in. NEEA's work is funded by local utilities, and for 22 years, NEEA has led local and national scale market transformation efforts to advance energy efficiency goals. But this would be the first demand response market transformation effort.

Duhan: Marc Hoeschele, from Frontier Energy, wanted to know where is the heat pump water heater technology in terms of moving CTA-2045 as a standard feature?

Koch: That's a heat pump water heater acronym. We're only in the initial learning curve of the industry adoption, but we're starting to see momentum building. And, since there's already electronics in a heat pump water heater, that product is going to probably be the easier solution versus the electric resistance tanks that require electronics to be built into them. Heat pump water heaters inherently are the first wave of deployment, I think, that's easier to do.

Duhan: Hillary Olson wants to know what was the adoption rate and install outreach strategy?

Koch: This was a three-year pilot project, research in nature. For heat pump water heaters, we approached utilities that offered a rebate for heat pump water heaters.

We had those folks reach out to the customers that received rebates and we got somewhere around 10% adoption into our pilot from existing rebated customers. And then to attract customers with electric resistance tanks, we had a very specific targeted low-income property owner that was able to manage more aggressively in that one campus. It was about 270 customers total, so it was a small-scale effort, not mass market.

Duhan: I know in the overview you talked a lot about the CTA-2045, do you have anything to add about it from a description and how it works from both the utility and the customer perspective?

Eustis: A few more highlights. It's a port and one of the advantages of a port, like a port on your computer is that it's totally secure. Nothing goes in or out of it until you actually plug something in. And that's much more important in an appliance (versus a computer) because usually the firmware that's in an appliance sits there for 10 to 30 years and the ability to fix a security problem, if a flaw is discovered with the communication process inside the device, is extremely difficult. With a communication device plugged into the port, in the worst case, if the firmware can be updated over the network, you simply replace the communication device, and nothing ever happens to the appliance and it remains secure. I also want to emphasize that in this pilot, most of the customers installed the communication device themselves and over time the process could be made, if it was like 4G LTE, much simpler than connecting to the customer’s Wi-Fi network. Literally the customer would plug in the 4G LTE device and they would be done. In our case, they had to connect to the Wifi network, which was often problematic for the utilities we the connection went down.

Duhan: You've talked about really high customer satisfaction. What do you think contributed to that?

Eustis: I think part of it is the simplicity of plug and play which means there was no need to schedule an appointment for anybody to show up. The customers didn't have anything to manage, although there was a website where they could override utility commands at any time they wanted. Another reason might be because we marketed the program as a new type of way to help integrate high levels of wind and solar generation. And for many of the customers, at least in our neck of the woods out here in the Northwest, they feel good about trying to help work towards ways to integrate more renewable energy.

Duhan: I liked the simplicity of it because here in Maryland, in addition to being installed by the utility, then they have to have a separate inspection by the county that they live in. And when you look at the combination, it's costly to the utility and the customer has to have two visits, one from the utility to install it and one from the inspector. So that's really nice. Ian Walch with Centrica asks, are customers enrolling in DR themselves or automatically enrolled in these programs? Do they even know that they're in DR?

Eustis: For most of the customers we did recruit them through formal marketing as a pilot. Then we sent them the communication device. Most of the resistance tank customers were located at a low-income campus and they were automatically enrolled, but all the customers knew they were being managed some of the time, but they never knew when. We didn't ever give advanced notice. Also, I want to give another example of how powerful the CTA-2045 approach is as a tool to program design. If CTA-2045 really takes off via market transformation and after awareness campaigns, it would be possible to implement a price-based DR program where the customer could go down to a store like the local Walgreens, pick up a communication device that is there in the checkout line, they go home, they plug it in, and the appliance would immediately start to hear the broadcast price signal and their appliance would now be able to reduce the customer's electric bill. There wouldn't even be a need for the customer to inform the utility. That's just another example of how simple and flexible program design can be with CTA-2045.

Duhan: So, it's truly pure plug and play here. Are there a lot of companies out there that make the CTA-2045 communication module?

Koch: Not many, but it's growing and so the early starters were e-Radio Inc., SkyCentrics, OATI, and Intwine Connect. And now companies like Itron and LG are looking at the option. So small but growing.

Duhan: Can you send an Open ADR command to an appliance using this technology or the port?

Koch: Yes. We've been hearing a lot of discussion about OpenADR versus CTA-2045. They're really very different things but they can play together, and in fact EPRI has recently published a report that provides more details on how to use OpenADR to send CTA-2045 commands. Basically CTA-2045 is a platform that, like Conrad said, you can pass any kind of command through there. So OpenADR is already supported as part of the CTA2045 specification; this feature means that you're just bringing the OpenADR commands through the port. So, as a port, CTA-2045 is a more robust and supports OpenADR as well as SEP (IEEE 2030.5), BACnet, etc. So in other words, you can use OpenADR all the way to the appliance through CTA-2045, but not the other way around. So, CTA-2045 is more inclusive, i.e. a broader solution, OpenADR is a more specific solution designed to work over the Internet between to computers.

Duhan: If a customer wants to override an event, I'll call it an event day or an event hour, can they do it and how?

Eustis: There were two ways customers could override events. Either way the override period was 24 hours. The feature works best if the customer implements the override before the high hot water use period. For example, if they were going to have house guests, or they knew that they were going to need a lot more hot water, they could either go to the device itself and push a button on the water heater or they could login to their personal web portal to start the override. The web option means they would be able to start the override from anywhere they wanted to.

Duhan: You're talking about a web portal. Is there an app or do you have to log into a web portal?

Eustis: In this case our communication provider was e-Radio. They created a unique web portal for each customer where the customer could log in and implement the override option. For this small project we did not develop a phone app.

Duhan: What are the advantages of the CTA-2045 approach compared to a simple connection to the cloud or something like that?

Eustis: The world of standards is a bit confusing, but because CTA-2045 is a serial data port it enables everything, right? It's just a standard way of accepting ones and zeroes at a serial port on the appliance. Serial ports like CTA-2045 have been used for decades. So basically, if the socket exists on all appliances that come out of the factory, those with existing electronic controls can add a port for probably about a dollar (per tank). The port can be added in addition to a Wi-Fi connection to the cloud. The port can be added to every product with electronic controls even if the product doesn't support a Wi-Fi connect. So now, with the same port on every appliance, you can use the same marketing for every single appliance. The customer experience is always the same: "We'll send you a device and you'll plug it in". This is much simpler for the customer than the cloud approach which is unique to each vendor. Another advantage, utilities don't need to enter into agreements with vendors, nor do they have to manage the application interface to that cloud server. Also, the appliance is future-proofed, as we mentioned earlier, for the life of the device. The customer can change the communication method, or even their service provider; in other words, the customer is always in charge. The customer can always change and choose whatever value proposition appeals to them. For example, they might start with a utility program, but later as the complexity of energy management in their home increases, say by installing a home battery backup solution, they could switch to a whole-home energy manager device where all appliances talk to the energy manager. Most times the energy manager might simply pass the utility price information to all appliance, but during an outage the energy manager takes over control so that the battery storage system is not overloaded and the battery duration in maximized by customer preferences. How would this be possible if the energy manager device must communicate through each vendor's cloud? No vendor's cloud solution will work if the outage also affects the Internet connection. In two words, the CTA-2045 port is very versatile.

Duhan: Greg Harr with Evergreen Consulting wanted to know, will ANSI/CTA-2045 apply to other Internet of things (IoT) Things devices for future DR, EV, battery backup, et cetera?

Koch: Yes. The standard was written with DR-centric appliances in mind. For example, Siemens has an EV charger that has a direct port. Mitsubishi, most of Mitsubishi's residential heat pump product offers a CTA-2045 adapter. So those are examples of other appliances that are beginning to show that opportunity. And I think the more that we discuss and show the value here, hopefully it will gain momentum in other appliances.

Duhan: Did you use the customer's Wi-Fi network? And if you did, how did that work out?

Koch: Yeah, we knew going in that using the customer's Wi-Fi network was not a reliable solution, but we had the need to gather data and the FM signal was only one way. So, we implemented Wi-Fi as a necessity to gather data and we proved to ourselves again that we had about 20 to 30% repeated points where Wi-Fi issues existed either, you know a router change or a password change, or the distance wasn't reaching the water heater appropriately. So yeah, we're not fans of Wi-Fi but we used it as an expedient solution.

Duhan: I heard you say that the CTA-2045 standard was designed to be used on multiple residential appliances. Can the same, utility-specific communication module be used on different appliances that offer the compliant port? Like besides the water heater, what about the HVAC equipment, EV charger, refrigerator?

Koch: Right. So that's the wonderful value of the modular port. The appliance manufacturers have repeatability, they can build the same thing independent of specific needs for different utility programs. Each utility picks a different communication method and may change over time too. But if I'm utility A and I pick my AMI system, for example, I can use that same widget and plug it into a water heater, plug it into a HVAC piece of equipment, a thermostat, what have you. I'm using that same hardware piece of equipment on multiple appliances. So that's the beauty of it. It gives utilities a lot of flexibility. It gives appliance manufacturers known repeatability and standardization.

Duhan: David Bourbon with Mitsubishi Electric Train HVAC U.S. LLC asked, what would you like to have changed about the CTA-2045 products to make them easier to use?

Eustis: I can think of a couple of things. One of the most important, there's a relatively new feature in the CTA spec, one that we weren't able to test in this project, but it's a way for the customer to indicate to the appliance how aggressive the curtailment should be. So, think of it like a comfort slider control knob where there might be settings between zero and ten. If the customer selects "0" you get the least comfort, but it also means the most aggressive setting for utility control and this maximizes the bill reduction. Or at "10", there'd barely be any response and it would maximize the customer's comfort from the device. This CTA-2045 feature will be very important to getting more utility benefit per device because, as one of our vendors said, in the water heater, they have to implement conservative, non-aggressive utility control because they have to meet the needs of every customer. Even though they know how to be much more aggressive, they can't make that the base setting for all customers.

Eustis: And another desirable change being discussed for both vendors and utilities, is about including the USB physical socket as one of the approved socket types. Right now, we have a DC form factor, an AC form factor, but because these sockets are produced in low volume they are expensive, by switching to the USB form factor it will be cheaper to implement and that cost savings can be passed on in the product. So that's something that we're looking at.

Duhan: How did customers from eight different utilities all receive the same control message?

Eustis: Again that's the beauty of having flexibility to pick any communication method. We chose FM because FM radio towers already exist where the participating utilities serve. In fact, with one tower in Seattle, one in Portland, and one in Eugene we could serve 7 of the 8 utilities. FM stations can pass digital information. We used the same method that tells your car radio the name of the song that is playing. A variant of that protocol was developed by e-Radio about 10-years ago to implement demand response. So, all that you have to do in order to enable communication to an area is find an FM radio station manager willing participate, and eRadio can setup a connection in a couple weeks. With the connections to the FM tower in place, we simply send out one message to e-Radio. They sent out simultaneous messages to all the FM towers that were subscribed and then all the customers got the same exact message within seconds. The response time is very fast for broadcast control and response time doesn't change if you have 5 million customers.

Duhan: I'm going to combine the last two questions and that's how are customers notified about events? And how did you evaluate customer satisfaction?

Koch: Now, we did not notify customer of DR events. If they felt that something had gone wrong, they made comments via their personal web portal webpage and then we would follow up. Most of those complaints were about running out of hot water but often we weren't even controlling them, because we did one week off, one week on. And, the satisfaction evaluation, Conrad?

Eustis: The report that we cited goes into it in detail, but the most important tool was an end-of-project survey where we asked typical satisfaction type questions. And that was after most customers had participated for at least a year. Remember they had been receiving a constant stream of DR events every day, although in alternating weeks.

The conversation above is from a webcast recording at https://bit.ly/3aFzLZc

Thought Leaders

Efficiency Vermont, Green Mountain Power, and Dynamic Organics for Flexible Load Management

Presented October 3, 2019

This project demonstrated the importance of partnerships for successful peak load management to benefit Vermonters, reducing carbon and the overall cost of the energy delivery system. Efficiency Vermont had a longterm customer relationship with Brattleboro Retreat, a healthcare facility in Southern Vermont. The project renewed utilization and controls optimization for a 1990s legacy, 3.2-MWh chiller and ice storage system.

Green Mountain Power (GMP), the local utility committed to fighting climate change, developed a strategy to share grid benefit and savings with customers from shifting load off peak. Dynamic Organics developed a custom controller and dashboard incorporating weather, electric grid demand and pricing, and HVAC system data simultaneously to allow remote control and automated operation of the ice storage system. A trial of the system during an early summer peak event was successful, and that led to development of an innovative pilot (currently enrolling 10 more customers with diverse flexible assets) to demonstrate grid and customer value. The goal is to then make this a permanent rate option for commercial customers who have flexible load.

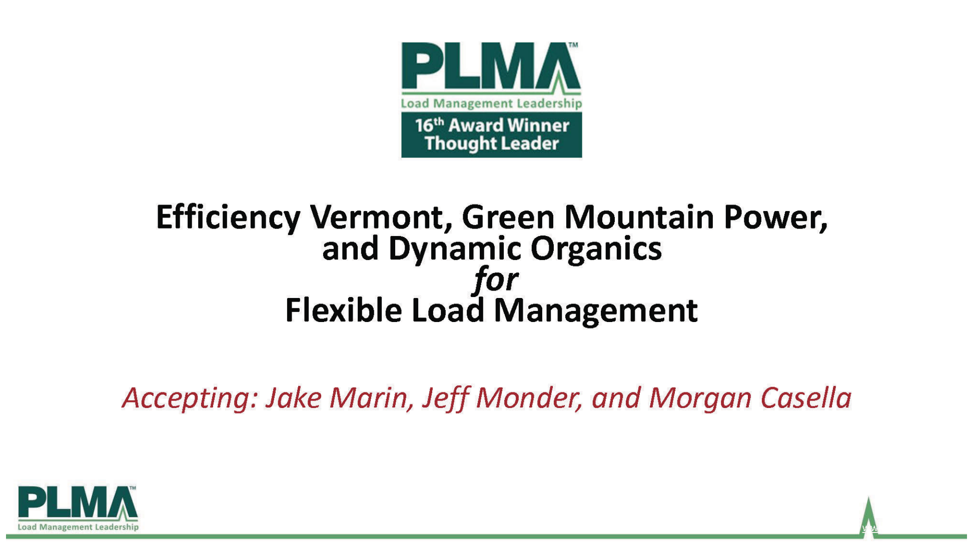
Dialogue transcript:

Laurie Duhan: Today, we have Marcus Jones from Energy Vermont and Morgan Casella of Dynamic Organics, and they'll discuss an application for flexible load management which won one of PLMA's Thought Leader Awards. Marcus and Morgan, can you introduce yourselves and tell us a little bit about the program?

Marcus Jones: Sure. This is Marcus Jones with Efficiency Vermont. I'm an energy consultant working with commercial and industrial customers throughout Vermont. We started out this project with a proof of concept at the Brattleboro retreat where they had an ice storage system that Morgan Casella had seen and learned about, and we met together on a job meeting that the customer had called us to and saw the opportunity for utilizing that system in a different way than it was currently being used to benefit the grid. That's where we kind of started all of this, which eventually led to a flexible load management pilot with Green Mountain Power in a partnership with the three organizations that helped get this award.

Morgan Casella: Hi, Morgan Casella with Dynamic Organics. We're a renewable energy development and integration firm, and we've been working with Green Mountain Power for five years discussing the opportunities of a demand side management and a more continuous application of that, flexible load management.

One of our customers, the Brattleboro Retreat Mental health hospital, had an existing obsolete ice storage system with 3.2megawatt hours of ice storage capacity. We were able to develop a new control software package for them and work with Green Mountain Power to



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leverage the use of that asset to reduce peak demand times of the grid in terms of capacity and transmission peaks, monthly and annually. In 2018 that proof of concept showed great performance and viability in the performance period. We used 21% more energy over the course of the two months, but we reduced the utilities costs to serve that load by more than 70%, and that spurred an expansion of this work into the flexible load management pilot that we're currently helping to facilitate with Green Mountain Power and Efficiency Vermont. That Pilot has 10 different commercial industrial users.

Duhan: While you're speaking of that, could you can also tell us the timeframe to get this from project to fruition?

Casella: The initial proof of concept was developed and tested last year. Green Mountain Power operates in Vermont under an alternative regulation plan, which gives them the fantastic ability to pilot different types of innovations. Under that framework we worked with GMP to develop a pilot that could roll this out – developing a pass-through mechanism that provides customers with 70% of the proven savings, generated from counterfactual time-series models of performance during these peak hours.

The incentive used in the proof of concept at the Brattleboro Retreat allowed us to expand and test the efficacy of this pass-through incentive structure which started in June of 2019. The timeline for this current Flexible Load Management pilot will run for 18 months - so were through the summer performance season with some great results. Unlike a lot of other states where it may be more difficult to get to that pilot status, this took a simple approval from our department of public service and public utility commission and we were ready to go on that in terms of testing with the small customer base from submission to approval for the pilot in 6-weeks.

Duhan: Ice making's not really a new technology. So, what was different about this application and or how is it applied differently?

Jones: The ice storage system was set up is just on schedule to make ice regardless of what was happening the next day. You know, if it was going to be 60 degrees the next day, the system would still go in and make ice, and it was just kind of set up as a block schedule to always try and maintain. There were other inefficiencies in the control sequencing that didn't allow it to be fully optimized. What we did here was look at using the ice only when it was necessary and not always maintaining it. Morgan can speak a little bit more about the algorithms they were using for that.

Casella: We just built out some optimization algorithms, so this was not a simple on and off controller on static time-periods. We forecast what the building cooling load is likely to be the next day and then make a proportional amount of ice for that time overnight while grid demand is lowest. It does take more energy to step down that temperature lower with the ice making (output at 19 degrees) versus 45 - 55 degree output for standard chilled water loops - so we're cognizant of that. We tried to co-optimize for the customer's and the utility's benefit and align building and grid efficiency. We might normally only think about the non-coincident building peak demand for building efficiency, whereas when considering the efficiency of the grid, we also need to think about what the coincident grid peak looks like. So, our software help to do that – bridge between the utility and the customer to co-optimize the greatest benefits.

Duhan: I have a question that we received in advance from Howard Henwood from Generac and he asked if gas generators are used for any of the load response?

Casella: Not in this pilot. EPA Tier-4 generators are the only type of generator that would be allowed (emissions-wise) for emergency demand response. This pilot does not incorporate generators.

Duhan: This award was given because of a really interesting story of cooperation between Efficiency Vermont, Green Mountain Power, and Dynamic Organics. Where does that partnership lead to from here?

Casella: When we started into this we had worked with Dynamic Organics and work with Green Mountain Power for a quite some time developing these concepts around flexible load management. We had not worked too much with Efficiency Vermont before 2018; mainly because Efficiency Vermont historically looked at megawatt-hour reduction in energy, the total energy used side of things, and reducing energy use was the paramount goal. This project had more to do with megawatts and the power side of things. And where this has started from and where it is aiming towards is a clarification about what efficiency is, what the definition of that means in terms of what Efficiency Vermont's charter is, and looking past solely megawatt-hour reductions, to also consider costs, impacts of the grid along with the timing and basically understanding that it's no longer just about how much energy is used–it's about when. If we can get to a fully renewable grid, there'll be times where we want people to take off as much as they can when the sun is shining. And so, this is a step in the direction away from solely energy reduction.

Jones: What's becoming clearer as we saw at the PLMA conference is that the main thing isn't necessarily how much you use as when you use it. And that's really kind of driving a lot of the collaboration with Efficiency Vermont, helping to demonstrate how we can evolve our strategies to get to a renewable energy future. Collaboration is going to be key all the way through it. Working together with all the partners

Casella: I know that in terms of the Green Mountain Power customers we're working with, we've seen a large interest in participating in flexible load management, not just because of the economic benefits, but also because the customers are interested in becoming good grid citizens, knowing that they're actually helping in the broader sense to enable more renewables and reduce costs.

Duhan: Florence Gordon also gave us a question prior to the call; she's from ESWB Engineering and asked "who will be the entity that helps building owners see opportunities to have this become part of the load management"?

Jones: Efficiency Vermont is well suited to a step up to that role. We already have energy consultants in a majority of the large C&I customers out in Vermont and work with them closely on efficiency projects. This basically just takes our field of view and opens it up a little bit. We're still obviously always looking for efficiency, look into make a building as efficient as possible and then look at how flexible loads in the buildings can be identified where it makes sense to continue to partner with Green Mountain Power, or the other utilities to electrify in a beneficial way to reduce fossil fuels and to electrify without adding to any of the peaks. That's where the flexible load management piece comes in. The energy consultants now are starting to look at how we can shift some loads across there with the customers in a way that works and doesn't affect their operations or comfort drastically at all. So Efficiency Vermont gets to help in that area very well.

Casella: I'd love to just stress that flexible demand coupled with efficiency is a "one plus one equals three" situation, where you actually can help to show additional savings and rewards that you couldn't show alone with a standard efficiency measure. But combining that efficiency measure with some better controls and flexibility actually can provide better returns on that type of transformation project.

Duhan: I know Efficiency Vermont's goal is to help customers reduce energy usage. In the case of making and using ice doesn't it really use more energy?

Jones: Yeah, it definitely does. As Morgan pointed out in the analysis that they did, it does use more energy, but there again, it's using it at the correct [off-peak] time versus using more energy during the peak time periods. The chiller uses more energy to make ice when the grid is not constrained, whereas before it would use a fair amount more energy during the time when the peaks are occurring. So really trying to utilize when it's using power at the right time is the better benefit for the whole of Vermont and all of the rate payers and utilities. So, that's kind of where we're shifting towards.

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Duhan: We had another question from Leland Keller from Fort Collins Utilities about the platform or platforms used to coordinate flexible loads and energy storage and if there's one or more cost effective solutions.

Casella: Dynamic Organics' ultimate goal is to build that platform that allows the orchestration of these loads, including electrochemical storage assets. This current pilot is helping to show the proof points of where that would be. We know that historically a lot of different utilities work with different distributed energy resource management systems, DERMS, that use different types of typologies, telemetry, and standards. We're looking to continue this work with these utilities – Efficiency Vermont and Green Mountain Power, to try to develop an overall architecture and standards that allows us to expand this in a scalable and standardized fashion.

I know that Spirae is out in Fort Collins where Leland's from, and I'm sure she's heard of them, but overall, there seems to be some lacking places in the marketplace for that kind of top node platform that does this in a seamless way. Utilities around the country are finding their individualized solutions, and there are certainly some large players working in this space, but we're working more in a bottom up approach here in Vermont, at least from our company's standpoint on this. We have a platform that we employ in this pilot that provides customers with access to information, their energy and power use data, along with forecast grid conditions and called peak events and peak event windows – providing a feedback loop of information to the customer. Ultimately, that's what we're incorporating into our platform offering in the future. A way to get customers information and tie that information to an incentive basis. And that's where flexibility can come from.

Duhan: We also had a question from Ethan Goldman from Recurve. How do you measure the impacts of flexible load so that implementers customers, and the utility can agree on the results.

Jones: We have a data analytics group within DVT or in our parent organization, the EIC that has really been able to step up to the challenge of looking at the data and over the years it created a lot of good analysis for efficiency savings and this was a, a new challenge that they had to step up too and did a great job looking at with the modeling software that they use, looking at all of these different variables.

So they're able to kind of have a rolling model for the last 30 days that builds out what the customer would have done versus what they actually did to come up with a pretty good baseline that we're about to roll out to customers starting next month or the end of this month. They'll get their first reports with information about how they performed in June. We've been able to do that in house. That's now automated and scalable to future iterations of pilots if that's the way that Green Mountain Power decides to go.

Casella: Efficiency Vermont has provided some amazing EM&V work on this using time series modeling. They have proved more effective in this exercise than I thought they could ever be. They've tested the modeling backwards against two years of data – and it shows very promising results for the efficacy and accuracy of that modeling.

Jones: I think we could kind of elaborate on some of those if we wanted. Morgan is just kind of explaining maybe where it's gone with the pilot from here that this collaboration really has blossomed. The first Brattleboro Retreat is part of the pilot, but then nine other customers all across the board from large industrial down to small commercial businesses and college campuses where it's proved very fruitful this year to show the cost benefit. By giving customers information and letting in a slight incentive, it encourages them to alter their behaviors to match.

Casella: For example, we have a customer who has a large compressor load. They have storage capabilities with the gas they're compressing, so they have been able to consistently reduce 1 MW to 1.5MW for the pilot for five-hour windows during peak demand events. That is an incredible cost-effective basis for storage compared to buying a similar electrochemical battery. We have another group that is a not fully hooked up yet but will be utilizing a wastewater treatment plant's anaerobic digester (with a non-fixed Headspace). They will reduce their AD generator output and store biogas during the day while the sun is shining, pulling electricity from the grid while its more renewable. As the sun goes away during the afternoon ramp, we'll start to use the gas and increase output through the generator. In this sense we are able to use a biological process to help to levelize a variable renewable generation curve and reduce the ramp rates in the afternoon.

We also have other customers who have ice skating rinks, commercial buildings with HVAC, customers with thermal storage, etc. So, this is showing a whole array of different commercial & industrial applications of flexible load management. We'll begin planning for expansion of this pilot or program into a tariff or expand the pilot and further test incentives with additional customers within GMP territory. Working with Efficiency Vermont we can also help to provide this knowledge base and programmatic implementation background to other Vermont utilities as well.

Jones: With some of the customers it's really interesting to see how they're able to adjust loads throughout the day without really having any noticeable effect on occupant comfort–within reason. One of the college campuses is able to raise and lower some of their set points based on the information they received from Dynamic Organics, and I have not received any complaints. So everyone's happy, but what we're seeing is that at one point you kind of believed that a building's load shape was consistent and not able to be changed based on what was happening in the building and at least for office spaces and college campuses, it's able to be adjusted and shaped within reason to meet what the grid might be needing. There's a lot of good learnings so far and we hope to keep learning that and possibly getting it out into a couple of other customer sites just to prove that it wasn't just a one off project.

Casella: That's an example of a direct load control that's a using an API from our platform – sending a 24-hour rate schedule to that campus. We also have examples of kind of manual curtailable and direct load control with executable control, demonstrating different frameworks of demand response that we're working with within this first pilot.

Jones: I see a message that came in about what the typical incentive for these kinds of projects. It's a very customized incentive just because it was a pilot. So, trying to, help move these customers forward, Efficiency Vermont helped with the cost of sub-metering. Not every customer of the 10, but the majority of them have engaged sub-metering installed and are pulling that data out, so we can see how they're doing in real time. And then in some cases we helped with the cost of building management system upgrades and control programming specific to the flexible sequences. So, it's a cost share with the customers–they are paying in, but this is a pilot, so that's just kind of the way it's worked here. We are working to see how we can develop a program to support flexibility going forward in the future. So, there's no set incentives at this point.

Casella: Well, the incentive for customers in this happens to do with the RNS monthly peak that is credited at 70% of what the value is to the utility. And so that's a $6.60/KW savings on what the customer reduced during that monthly peak hour. For the annual peak, customers can receive 70% of the FCM payment, which in new England this year is around $58/KW of modeled flexible demand savings.

These economics allow customers to save money for their businesses. One of our customers is actually even discussing how they pass through this through to their customers – with contracts in the future where they can incent their customers to be more flexible on delivery in exchange for a portion of the pass through benefit Green Mountain Power.

And just background to some of the question that Ethan Goldman posed in terms of an ARIMA models or SARIMAX models. This is all just time series modeling, with some exogenous regression analyses.

The conversation above is from a webcast recording at https://bit.ly/37CUYBm

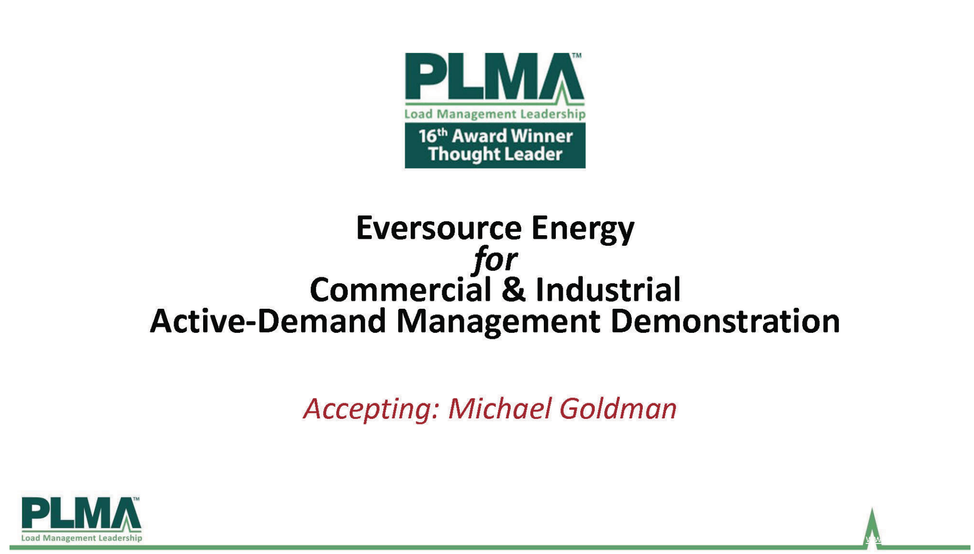
Thought Leaders

Eversource Energy for Commercial & Industrial Active-Demand Management Demonstration

Presented October 17, 2019

Eversource introduced an innovative holistic approach to reducing peak demand among commercial and industrial (C&I) customers. Their active-demand management demonstration utilized a wide range of technologies, including battery storage, ice storage, phase change material thermal storage, advanced software and controls and wi-fi thermostats, to engage large and small C&I customers. Not only did the demonstration successfully engage with a variety of C&I customers, it also reduced the 2018 regional peak by 8.7 MW.

This demonstration project shows that taking a holistic approach to demand reduction is necessary for the long-term viability of demand-reduction programs and paved the way for the development of an approach to peak-demand management featuring various technology types, each using open communication protocols that connect to a single dispatch platform.



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Dialogue transcript:

Michael Smith: Today we'll be hearing from one of our award winners at the 16th PLMA awards, Eversource Energy, about their commercial and industrial active demand management demonstration project. We're joined today by Michael Goldman of Eversource Energy.

Michael is a director in the energy efficiency department at Eversource Energy, the largest energy delivery company in New England. His team at Eversource is responsible for the development of the companies behind the meter distributed energy resource strategy. He is a frequent contributor at conferences and articles on distributed energy resources and their impact on the evolving grid. Prior to Eversource, Michael worked as a strategy and operations consultant in Deloitte Consulting's energy practice.

Michael, thanks for joining us today to talk about your project. Just to get things started, can you talk just a little bit about the basics of the project? Talk about how it originated at Eversource and what problems you were looking to solve.

Michael Goldman: I'm very excited to be here today to talk about our C&I demand reduction demonstration project that won one of the 2018 PLMA thought leadership awards.

Really, the origin of the project and what we were trying to figure out what we could do to help reduce the overall ISO New England system load. We're really trying to do that to figure out to what extent we can have economic and environmental benefits for our customers.

One of the things we were trying to do is see if we could reduce those peak loads on the absolute highest days of the year, and then maybe potentially lower the amount of capacity that was being purchased in the region. Then, by lowering those peaks, what we'd also be able to do in turn is reduce the amount of inefficient generation that was being run so that we could also have a beneficial environmental impact in addition to those economic impacts for our customers.

Smith: I understand that there were quite a few technologies that ended up in play in your project. When you guys were first scoping the project, what kind of research was done to determine what type of technology you wanted to include in the demo project in order to meet those goals?

Goldman: We didn't come into the demonstration projects with any sort of preconceived notions of what technologies might be best. What we wanted to do was a lot of load research. Really understand how our customers were using energy, and when they were using that energy, and that we would then try to match a set of technologies to those different types of, customer load shapes.

What we did is dig into the15-minute-interval data. We discovered what we call patterns within the load shapes, and we essentially developed customer types. Then from there we tried to decide or figure out what types of technologies were good fits for the individual types of customer types, and the individual different types of load shapes that we were seeing. Ultimately the idea was to pair the different technology types with the different customer types in the load shapes that we were seeing.

Smith: In addition to some of the goals you had outlined earlier, were there any key research questions that you were looking at, and a strategic planning going forward with how you would use DER?

Goldman: Absolutely. We had a whole host of research questions that we were trying to get answered. We were really interested in understanding better, what were the different types of customer reactions? What was the customer acceptance of these types of solutions? More so than that, how do you reach these customers? What are the most appropriate delivery channels? Is it through project developers? Is it through ESCOs? Is it through some other type of channel? We were very interested in better understanding what solution types were best for each type of customer. Just as an example, our utility is in Connecticut, Massachusetts, and New Hampshire. We have the fishing industry in parts of our Massachusetts service territory. Looking at things like thermal storage as maybe a good solution for a fish processing plant, it's a longer duration type of solution as opposed to a lithium ion or a battery that might have a shorter duration, something like that. Really understanding those different customer types and what they were using the solutions for.

We wanted to know if we could address issues both during summer peaks and then when there's high winter demand, as well, really trying to get a better understanding. What is the scale of the opportunity within our service territory? Then, are there any sort of associated barriers either from a technology, or a business model, or regulatory standpoint, To a more full-scale development or deployment of those solutions.

We had a list of, say, high level resource questions that we were trying to work through, that I just mentioned some of them. But then we also had more what I'd call granule-level or micro-level type questions. Quite literally, how much energy was being displaced for how long using these types of solutions?

We had seen some more generic research that had been done in other parts of the country, but really what we wanted to understand was, given our specific climate, given our certain types of customers what were the solution sets? What were they going to say specifically for the types of customers that are in our service territory?

Smith: You've addressed some of the goals and how you were looking to pair projects and customers. Could you tell us a little bit more about some of the demonstration projects that ultimately made it, and which customers those were paired with, and how that process evolved?

Goldman: Sure. At the outset, we were really trying to find an innovative approach to reduce this peak demand issue amongst our commercial and industrial customers. What we thought ended up distinguishing this approach in the end was just the breadth and the recognition that really different types of customers, they require different types of strategies and solutions in order to bring them into a program, and at the same time hopefully minimize customer operational interference.

One of our key tenets was that, if we can find solutions that don't cause customers to really have to alter their operations, or they don't really know they're operating but the solutions are constantly operating in the background, that's really going to encourage customer participation and really prevent customers from opting out of the programs.

One of the things that we had noticed is that, in some other areas, we'd see more of a one-size-fits-all type of approach. The issue there is that you may not be able to get certain customer sub-segments to participate in your program.

What I failed to mention earlier when we were doing some of our initial research and some of our initial due diligence, we were essentially looking at that ISO load shape because we were trying to reduce that peak at the ISO New England level. When we started breaking that down and we started to essentially decompose it into its constituent parts, what we discovered was that there was no individual load class or customer class that was responsible for really driving the shape of that peak. When we started looking at load shapes at a customer class level, you could really see a contribution of all the different customer classes. That was one of the reasons at the outset that we thought we needed this more holistic approach, and that we really couldn't rely on this more of a one size fits all.

As we went through this process, and we had already come to the conclusion that we needed to develop solution sets that were going to be more all-encompassing and reach a wider variety of customers, that's when we said, "Okay, now we need to have a lot of different solution types," but not too many that it's not manageable. What we had settled on was battery storage, so essentially lithium ion batteries, ice storage ... Essentially thermal storage, but two types of thermal storage, ice storage, and then phase change material. We also introduced advanced software and controls, and then two types of what I'll call more traditional demand response or curtailment type services, one for large C&I customers and then one for small business customers that was based on a wifi-thermostat-based approach, similar to what we might see with residential customers.

The thought process, again, was that we'd essentially have this one offering, but it would allow us to enroll a wide range of businesses, which we thought would be essential to how we were going to maximize this load reduction and then drive down that overall system peak. The ultimate vision really was to develop this type of holistic approach where we could have these various types of technology types, but hopefully each using either open communication protocols or something along those lines, so that back at Eversource we can aggregate all of these different solution types and then actually dispatch them in a coordinated manner so that we could have that larger impact that's this aggregated impact. Then hopefully that we can make a material difference within the system-level piece that we are trying to target.

Smith: This project's been underway for a couple years now. Can you share some of the key results you're seeing, and how they may be compared to any preconceived expectations you had before you started?

Goldman: Absolutely. We were able to install several large lithium ion batteries at offices and at some universities in the area. We were able to go into some cold storage facilities and put in phase-change thermal material. We were able to use ice storage units at several office buildings in order to offset the need for air conditioners. We were able to go into several other office buildings and install advanced software and controls.

We exceeded our target for our large commercial and industrial active demand, more of a manual curtailment type of load. Then on the small C&I side, this is one of the areas that I think we were a little surprised at actually how difficult it was to get more customers enrolled from that segment. That's a notoriously difficult segment to get a lot of participation, and especially in a program like this.

What we were seeing is that there were issues between who had operational control of the HVAC systems at small commercial and industrial or small businesses. There might be landlords that have control versus the tenants, or even within the tenants there might be an owner that's not always there who has operational control over the HVAC systems. It's not necessarily up to the folks that are in the building on a day-to-day basis.

One of the big takeaways from all of this is how difficult commercial and industrial can be. What's the right solution set for that customer base? I would say some of our other main takeaways were that installing batteries can actually take a really long time. There can be all sorts of issues that pop up that were not necessarily expected. But as we worked through some of these issues and we gained more operational experience, the hope certainly is that we can smooth some of that out.

Just by way of a couple examples, we actually encountered some local permitting issues where the local officials essentially considered storage as a generating source, and that where we wanted to put these units wasn't zoned for generation. It actually took a lot of outreach and a lot of meetings with the local officials to really educate them about what energy storage is and how it functions, and why we didn't consider it to be, essentially, a standalone generating unit.

There were issues in terms of how these types of assets go through the interconnection queue, which can sometimes take a while. We had to learn a little bit more about the civil engineering work that has to get done for these types of projects. Necessarily needing, in some instances, drainage ditches. We had one instance where the customer wanted to install security posts and they wanted to put it at one distance, but actually the fire department wanted them closer to the actual unit, so, in the case of an emergency, they could actually back their trucks up closer to the unit. Those were some of the things that we didn't really expect that can actually have a significant impact on the timeline for some of these projects.

In terms of how they performed, we were overall quite pleased with the performance. The lithium ion batteries work pretty much as we'd expected them to in terms of the load reductions we got. I still think we have some questions about the efficiencies of those types of assets, and the round-trip efficiencies, and how best to measure and calculate that.

Then one of the other things I would mention is, for advanced software and controls, one of the things that we ran into was our assumption that for these to function at their highest levels, some of these advanced software controls essentially have to be operating on the customer's intranet. Not surprisingly, that caused some cybersecurity concerns from the customers about having a third party come in and essentially have their software sit on the company intranet.

Those were some of our main key learnings from these projects. Our hope is that we can take these demonstration projects, and in many instances, we have taken the learnings from these demonstration projects and have begun to roll this out more programmatically across our three-state service territory.

Smith: It sounds like Eversource feels that this project was certainly a success. You mentioned the programmatic expansion. What's next with this type of DER portfolio at Eversource? Is it just rolling out, again, technology neutral across your territory? Do you have certain favorites you found where you think have the most potential within your customer base? What's next for Eversource?

Goldman: We absolutely want to roll this out programmatically across our service territory. One

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approach we've taken is a little bit more of a technology-agnostic approach. It's really more of a pay-for-performance program design where we don't want to dictate to our customers how they get load reductions. The customer is the expert about their facilities, about their processes.

What we want to do is come in with an incentive and essentially tell customers, "You're the expert. When we call for a demand reduction, you figure out how best to do that. We'll provide technical support if you need it," some customers need it, some customers don't, "but what we'll do is we will pay you an incentive based off of verifiable load reductions after the fact." We'll use the interval data to come in after we have had a season. We'll look at the average KW reduction during the times that we call the dispatch, and we will then pay an incentive based off of that measurable and verifiable load reduction. We think that's a really successful approach that we've used over the last year or two.

One thing I would mention is that we do have a specific call out, or, I would say, a different incentive level for storage. The reason we carved out storage separately is because we think it has other attributes that really make it attractive. What I mean by that is we can't call a traditional demand response event every single day. We just don't think customers will have a tolerance for that. If they're changing HVAC set points or they're changing production processes, or whatever the case may be, they can't do that every single day.

But I had mentioned earlier, one of the things we're trying to do is really minimize customer operational interference. By having storage installed and being willing to pay a little bit extra for that, folks can dispatch their storage and hopefully really notice minimal, or again, hopefully no operational interference. That actually allows us to dispatch it on a much more frequent basis. There's a real value to that. We essentially had a tiered incentive infrastructure where we paid one incentive level for a technology-agnostic approach, and then a higher incentive level for that storage approach. That's something we're trying to roll out more broadly.

You had mentioned, what else are we thinking about, and what else are we testing? One of the things that we're actually testing right now that we're trying to bring into our portfolio is managed EV charging, essentially using two different strategies to manage that peak load. One I'll call scheduling and one I'll call throttling.

On the scheduling, what we do is we can actually push a charging schedule through a level two wifi-enabled EV charger for customers that opt into the program. In that instance, a customer may come home, plug in their car at night, not have to touch it, go back inside, and we'll just control the charging, so it doesn't start charging until midnight. The customer will still have the charge they need by morning, but it won't be charging during those peak time periods.

The other strategy that I just mentioned is throttling. That's more like a typical demand/response type of event, where, during times of acute grid conditions or if there are peak times that might set the capacity requirements for the ISO, for a limited amount of time, we can actually send a communication, a dispatch instruction, again, to those level two wifi-enabled chargers and have them temporarily ramp down the charge rates for a couple hours until that event is over.

That's a long-winded way of answering the question, but we are both trying to scale this up programmatically and at the same time bring in new types of technologies, new types of measures so we can go after different types of loads as well.

Smith: It sounds like you have quite a bit planned, going forward. I just want to circle back on one point you'd mentioned. You have a technology-agnostic type approach and then maybe a more storage type approach. I'm curious both about that and if this will change going forward with EVs. What's your approach to M&V for these types of programs? Are you trying to treat them all the same? Do you have to customize your approach to storage and EV compared to other low reductions?

Goldman: What we try to do when we scale up is determine if there's an ability to do the M&V at scale, or whether or not each solution type requires some sort of specialization. What we found is we do need some degree of specialization in terms of how we're evaluating these different programs. On the batteries, for instance, we can pull data directly from the battery inverter, see when it charged and the depth of discharge, and for how long. That's actually a really easy way for us to be able to understand what those demand reductions were if you are using a battery.

On the technology-agnostic approach, it's a little bit more challenging, but luckily, they are already what I'd call relatively mature types of methodology. What we adopted was essentially what ISO New England does, which is essentially a rolling 10 of 10 baseline, where we look at 10 most recent days and we make some adjustments if there were outliers, or there might be an in-day temperature adjustment. We essentially look at the 10 most recent days to set a baseline, and then we look at the usage during the day when we call an event.

The EV chargers were also a little bit of a challenge, but what we were able to do is determine whether a customer was plugged in and charging during the event and time period. If so, we can look at what the reduction in load was during that time period. For the EV charging, one of the things I essentially failed to mention is, with the storage and the demand response, again that's a pay for performance.

The EV load management, that's more of a participation incentive. We're not going to pay you necessarily on how much you reduce, we're going to pay you for participating in the program. More on the lines of what we see on the wifi thermostat types of programs, where it's not based on your actual reduction, it's based on participating in the program and then responding to each event signal.

We had to take a little bit of a different approach. One thing that I think has been very helpful for us is that we've been able to contract with third-party independent firms that come in and essentially do the EM&V for us. What that allows us to do is take a step back and then read these reports. We obviously offer input into the program design and what the evaluators should be looking at, but at the end of the day, what we get is a completely unbiased view of how these programs are working and suggestions for improvement going forward. That allows us to have this continuous improvement and essentially a feedback loop where we can take those results and then improve the programs accordingly. That's one of the things that we think is really important, especially with some of these newer types of programs that might include newer types of technologies, is making sure we're refining the program design so that we're able to essentially optimize what we offer and have the biggest impact for our customers.

Smith: We have a couple of listener-submitted questions here on incentives. If you would just talk a little bit about how you developed incentives. Are you basing it on average load reduction, some peak hourly performance, worst hour performance? Then how you view the benefits of maybe the technology-agnostic versus storage, as far as the incentive that you think is appropriate.

Goldman: On the development of incentives, we have a couple of criteria in mind when we develop incentive levels. The first is, because these are offered through energy efficiency, our offering has to be cost effective. We can't incur more costs, which include incentive costs, than the measure or the offering generates. That's our grounding principle.

The second part of the incentive is we try to structure it in such a way that it's large enough that it motivates a customer to do something they wouldn't normally do without that incentive. But, at the same time, we don't want it to be too large, such that we're unnecessarily expending funds. That's not really a good deal for the rate payers. We try to strike that balance by giving just enough to motivate the behavior while not giving too much, and all at the same time, while keeping things cost effective.

In terms of technology agnostic versus the storage, the same general principles apply. One of the things we like about the technology-agnostic approach that I commented on a little bit earlier is that we're not trying to be overly prescriptive. We're not trying to tell a customer what types of measures or what types of activities they should be undertaking in their facility. These customers know their facilities inside and out way better than we ever could. They know where they can get those demand reduction savings. The point of the incentive is to tip them over that point where it makes sense for them to do that. That we can then aggregate all of the customers that are doing that, dispatch them at the same time, and have those overall system benefits, that's, in a nutshell, really the goal.

One of the things that I would mention that we did come across and we are completely aware of is, when you do a pay-for-performance program design and you start offering incentives after the fact, that doesn't necessarily help customers that have a first-cost issue. Some of these types of technologies, like batteries, can be very expensive. The customers or the developers still incur that initial upfront cost.

One of the things we wanted to do that we asked for in Massachusetts on a little bit more of a trial basis is whether or not we could offer a five-year incentive lock. Basically, it would allow us to lock in the incentive level for five years. There'd still be pay for performance. There are still performance risks that relies on the customer. You still have to perform at the level that you said you're going to perform at. But what it does is it takes away the risk that the incentive level is going to go away or go down.

That makes it a little bit more of a bankable revenue stream that customers can then use to get project financing, or something along those lines. To us that was really important because that's the complimentary piece to the pay-for-performance design that we think will allow more of these projects to go forward.

Smith: I want to just ask you one more question. For folks listening from maybe other utilities across the country who are interested in expanding their load management capabilities with new DERs, do you have any key basics, where to start? I know you discussed some takeaways as far as potential pitfalls with permitting and siting, but if you have anything else to share there … Also, how to gain traction with, not only leadership within their own company, but also their regulator.

Goldman: One of the things we did when we first started this out is, again, we didn't go into this with any preconceived notions. We essentially went out to market with an RFI. We put this out there to technology and solution providers and said, "What technologies are out there? Come back to us with solutions." That really was the first step for us in order to frame out what we were going to do, and then have an idea of the different types of technologies we wanted to propose.

I think one of the reasons that we were ultimately successful with our regulators is we went in with a pretty well thought out and a pretty well defined plan. That RFI helped inform the technology choices.

I spoke at the beginning of the session about all the load research we did in terms of customer load shapes, and how we essentially disaggregated the ISO New England load shape into the customer load shapes, and then we married that with the RFI responses and the different technology types. We had a pretty compelling argument, I think, at that point. I think that was really helpful on bringing regulators onboard as well.

Again, maybe a long-winded way of saying that, really do your due diligence, do your market research. You usually get positive responses when you're able to do that and show that this is a really well thought out approach and program. But, at the same time, you go into it with the best of intentions, but make sure that you're flexible as well. You will get curve balls that you didn't expect, whether that's on the permitting, or the interconnection, or who knows what else. You almost have to expect the unexpected. Be flexible enough to deal with those issues as they come up.

Smith: Great. I think that's really some great advice, Michael.

The conversation above is from a webcast recording at https://bit.ly/36tetdV

Program Pacesetters

Indiana Michigan Power and Tendril for Residential Integrated Demand Side Management Approach

Presented July 11, 2019

Indiana Michigan Power (I&M) worked with Tendril to implement Orchestrated Energy, a connected thermostat demand response program dramatically shifting peak load and improving the energy efficiency beyond that of smart thermostats, without sacrificing customer comfort. I&M uses this program as a customer engagement tool that also provides demand response load while keeping customers comfortable. I&M envisions this program as another way to become a trusted energy advisor to their customers on how to utilize the connected home.

IM Home ran on 2,132 thermostats in Indiana and 423 thermostats in Michigan from May 2018 to September 2018 leveraging smart thermostats from ecobee and Honeywell. The program saved 80,220 hours of cooling runtime in Indiana and 8,736 hours of cooling runtime in Michigan. This works out to more than 263 MWh saved in a little more than four months of operation, allowing the program to deliver gross realization rates of more than 100% in both states. This is in addition to the traditional savings already delivered by smart thermostats.

Dialogue transcript:

Laurie Duhan: Today, we have Emilie Stone from Tendril and Jon Walter from Indiana Michigan Power and they're going to discuss their Residential Integrated DSM approach that just won PLMA's Program Pacesetter Award. First, Jon and Emilie will introduce themselves and tell us a little bit about the program.

Jon Walter: This is Jon Walter with Indiana Michigan Power. I'm a manager here at Indiana Michigan Power, which is an operating company of America Electric Power and I&M has service territory in two states in Indiana and Michigan.

We operated the IM Home program in both of our state jurisdictions, Indiana and Michigan. Overall, the program is an Integrated DSM program that offers both demand response and energy efficiency to IM residential customers through a partnership between I&M and Tendril Networks using smart and/or Wi-Fi connected thermostats and residential customers homes. So with that I'll turn it over to Emilie and let her introduce herself.

Emilie Stone: Thanks, Jon. My name is Emilie Stone and I lead product for Tendril's demand management solutions. So, our Tendril branded version of that is Orchestrated Energy and that is the platform that sits behind IM Home, which is Indiana Michigan Powers, demand response and energy efficiency (EE), smart thermostat program.

Duhan: I just have one question to start off with and, what is IM Home and what makes it so unique and actually worthy of the PLMA pacesetter award?

Walter: IM Home is a combination residential demand response and energy efficiency program that remotely manages customer on Wi-Fi connected thermostats using Tendril's Orchestrated Energy platform. What makes it unique is that it's an integrated demand side management program open to all residential customers that have compliant HVAC technology in their home, especially a smart or a Wi-Fi connected thermostat that provide Wi-Fi access to I&M and Tendril to manage the thermostat remotely for both demand response and energy efficiency.

Stone: Just to add onto that really quickly, Jon mentioned that it's both DR and DEE. What we're really trying to do is on those days where Indiana Michigan power has a demand response need, be it within an I&M territory or actually related to a PJM event, we can absolutely just batch an event and get those load shift benefits for days where we're not running an event. Our default is to operate with an energy efficiency target.

So, we're actually deploying schedules to each of those thermostats in the territory that really is optimizing for energy efficiency or energy reduction overall. So, you're

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Accepting: Jon Walter and Emilie Stone

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getting a load smoothing effect on days when you're not running a DR event while still reserving the right to get that load shift benefit should the DR event occur.

Duhan: You touched upon this, but maybe a little broader. What are the objectives of IM Home?

Walter: The objectives of IM Home are threefold, but primarily first, IM Home was developed with the intent to improve customer experience in demand response and in demand response events using current available technologies today to residential customers as compared to the historical AC cycling switch that you'd put on the air conditioner to cycle the air conditioner. We really wanted to improve that experience for customers.

So, with that primary objective, we began designing the program. We had really, like I said before, three primary objectives for the overall program. The first one was to ensure ongoing customer satisfaction and comfort levels by adhering the individual customer set point preferences during both demand response events and continuous demand management (CDM) operation, which is the CDM aspect of it, is the energy efficiency operation of IM Home.

The second objective was that we wanted to improve upon the level of demand shift that we were able to achieve over prior technologies like AC cycling switches. We were able to do that by partnering with Tendril to focus the efforts by managing the thermostats using a home pre-cooling approach.

The third objective is we wanted to achieve energy efficiency as well, next level energy efficiency savings for customers that really just wanted to take advantage of the benefits of technology. So, we wanted to deploy a set it and forget it approach to create that next level energy efficiency through a continuous demand management approach using the customer Wi-Fi and the customer-owned thermostat. So those were the three objectives of IM Home for the program overall.

Duhan: That's interesting because I know here, where I am, and most utilities look at their demand response and energy efficiency programs separately. Even if they have a thermostat optimization program and a thermostat based temperature offset demand response program. Again, probably expanding on some of the things you already said, but why are you combining the DR and EE into one offering?

Walter: We want to take advantage and really capture the total benefits of both into one program to provide customers one channel to access those benefits. So, we combined demand response and EE into the one program to maximize and streamline customer and utility benefits through a single connected-device technology. The big data aspects available from connected thermostats and the behind the scenes data analytics that we were able to take advantage of from Tendril in their Orchestrated Energy platform that analyzes the home performance during advance response event.

It just seemed like the next logical step from a demand response and managing it through pre-home cooling is to deploy a continuous demand management approach as well to create energy savings through set point management all summer long through the summer cooling season, which is I&M's typical demand response season.

Duhan: If you can explain the link between the level of customers' demand savings and their actual energy efficiency improvement.

Stone: What we have found by being connected directly to the smart thermostats in customers' homes is, we can see through their set point changes and through the schedules that they put on the device quite a lot about customer preference. So, we are able to get a feel for whether a customer is maybe a super saver who is willing to have a really energy efficient schedule and is not bothered at all by a DR event versus somebody who maybe wants to actually participate in the event and they're okay with periodically being called upon to participate and being potentially inconvenienced, but they maybe are more interested in just getting that incentive. So, for the I&M program for IM Home, there is actually a per event participation incentive. So perhaps they're just trying to get that participation incentive and are less interested in the EEE aspect of their programs.

By looking at customer preference, we're able to model out what type of customer we're looking at. So, where you found really high satisfaction on DR days and really high participation in some of our events, we have actually less than 2% opt out. For EE days, we really take advantage of machine learning to identify which customers are more interested in an EE savings and we can get more energy efficiency out of those devices versus other customers who maybe are putting customer preference first. We call it mild, medium spicy.

There are the mild savers who just want to be comfortable and cool all the time. They maybe not the best resource for energy efficiency, but we absolutely still want them in the program to participate in load shift events. Then there are those customers who are really happy to say, be it for an environmental reason or strictly a cost savings reason or maybe even feeling like they're participating in the community. Those customers, we can give them perhaps a little bit more of a nudge towards an aggressive schedule that really delivers more energy efficiency savings.

To circle back to your exact question, there is not necessarily a link because most customers, who have signed up for this program are more than willing to participate in DR events. As far as EE savings goes, that really gets down to customer preference and customer behavior and being able to observe and learn from customer behavior as opposed to asking heuristically, "Do you want to save money or do you want to be comfortable?" We tend to find that what customers do speaks a lot louder than what they say.

Duhan: How does your Orchestrated Energy platform work to achieve all of this between DR and EE?

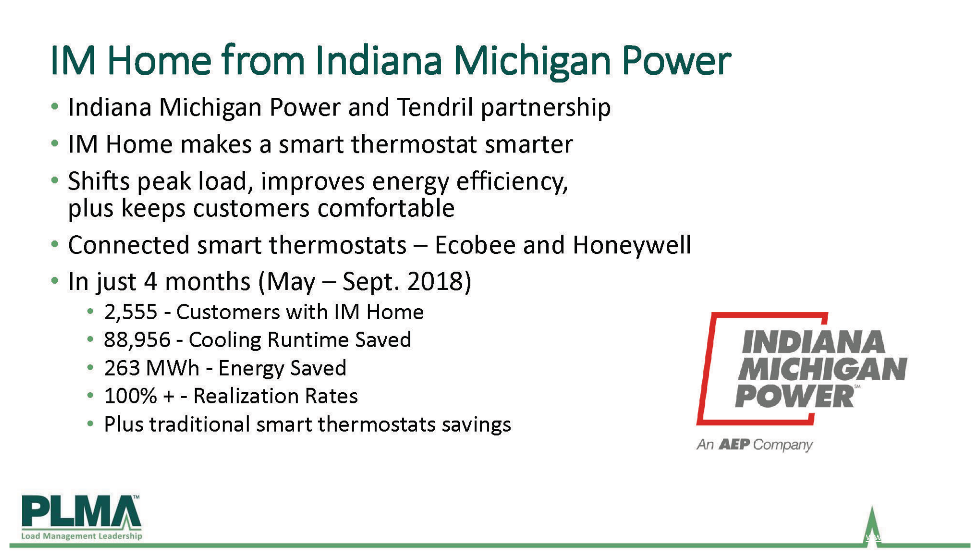
Stone: Our core technology is really designed to respond to whatever signal has been dispatched. So that could be DR, it could be EE, it could also be something like a TOU signal and it could be something like a wholesale market price. Basically, we're feeding that into our optimization and using everything we know about the characteristics of that particular customer's home, the weather conditions on the ground, their preferences around temperature and what their schedule set point is to develop a schedule.

For the IM Home program, we're operating on ecobees and Honeywells and we're able to dispatch personalized schedules every day. Our default is to optimize for energy efficiency unless an event is called. So typically, Jon is able to call events the day before, so we have plenty of time to adjust to sending a DR schedule. We dispatch those schedules around midnight, typically.

On certain events there may be a need to call on an event the day off. We actually had one of those last week. Jon had a very busy week last week and so we're able to actually switch the contacts from EE to DR and immediately start that pre-cooling process to be sure we're getting the low shift benefit as well.

Walter: Yeah, and that's exactly right. I might just add from a utility perspective or I&M's perspective, Emilie talked about that flexibility. Generally, we try to schedule a day ahead, but at times, and just from the nature of utility operations and loading and all that, we made sure that there were provisions in how Orchestrated Energy operated to be able to call demand response with only a few hours' notice. But recognizing that we're not going to get the demand response level that we would achieve otherwise if we had called it a day in advance. Just recognizing how Orchestrated Energy operates.

But we did make sure that there is flexibility to call events when we needed to and recognize whatever available demand savings or demand reductions that are for the event given the amount of time that we have.



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Duhan: I know for a lot of utilities that's included, there's a lot of the... I don't know the legacy or certainly the typical up till now with temperature offset, the cycling programs, whether it's cycling through a switch or through a thermostat. How is this process, IM Home better than that demand response program?

Walter: The results that we've seen bear out the benefits compared to this AC cycling program and AC cycling programs that I&M ran prior to deploying the Orchestrated Energy in the IM Home program to its customers. Compared to the AC cycling DR program, we're able to achieve next level demand response in energy efficiency benefits that both our customers and I&M are able to realize.

Essentially, we're able to achieve more demand response on a per home basis for any given DR event window than what we were able to achieve in an AC cycling event, either using adaptive control with the AC cycling or just a set runtime reduction approach.

On the energy efficiency side, we're able to help our customers achieve higher energy savings than... Traditionally, AC cycling programs have never really been considered to have energy efficiency savings and that's something that we wanted to tackle with this program. Given the Wi-Fi connectivity with the thermostats and the availability of data, we could continuously manage, even going out of a demand response event to avoid snapback and still achieve energy efficiency savings overall.

So we migrated that from the main responsive event to continuous demand management over the summer cooling season to be able to provide that ancillary and additional benefit to customers that we can help them manage their thermostat settings according to how Orchestrated Energy operates on a continuous demand management basis.

Stone: One thing I want to add onto that, Jon alluded to the energy effect over the day of a DR Event. One thing that we're really proud of with Orchestrated Energy is that lack of snapback effect. We call that optimizing for the last minute of the event. That basically means that at the end of the event, the house is still at a comfortable level where the customer doesn't feel compelled to go turn their thermostat way down and cause a giant load spike afterwards.

We actually had a program last summer that was evaluated by Navigant and they were pretty thrilled to show us one, that there wasn't a snapback effect and two, that across the population on average we were actually energy neutral for demand response days. So, we weren't just dumping a ton of energy into the home for pre-cooling purposes and then dumping a bunch of energy after the event. We were actually maintaining energy neutrality. So, it's getting that load shift benefit while not creating a lumpy load curve as a byproduct

Duhan: We had a few questions coming in when people registered concerning M&V. So, what I want to know is how is IM Home measured and evaluated?

Walter: We evaluated IM Home using items, third party evaluator, which was ADM and Associates. Their evaluation approach was customized to the data that was available in the program and according to how Orchestrated Energy operated both between a demand response event and the continuous demand management or energy efficiency component of the program. The evaluation report essentially addressed each different aspect of the program, DR and DE separately and measured those. There was control and task group methodologies used and also for the energy affects, they used mixed effects and maybe, I believe, a Tobit regression analysis as well.

So they used standard industry protocols to evaluate the program and that's born out that we got the results that we did in the evaluation and validated what we had anticipated that we could improve upon that I described before over an AC cycling program.

Duhan: Then from the customers' side, are they paid rebates?

Walter: Yeah, the customers are actually paid rebates in a couple of different forms. So initially, to get for customer acquisition into the program, I&M will pay a rebate for newly installed, bring your own thermostat, Wi-Fi connected ones, we'll pay a specific rebate for that. We'll also pay a rebate for any customer that has an existing BYOT thermostat on their wall, as long as it's compliant with what IM Home and Orchestrated Energy can operate, but we'll pay that rebate to existing customers if they newly enroll in IM Home. Then third, we also pay a demand response bill credit for any demand response events participated in.

So those are the three types of rebates that we pay in the program. I will comment that there is another customer benefit on the back end and from the energy efficiency piece that they get a bill reduction as well through the continuous demand management approach compared to what they would have seen otherwise, without the Orchestrated Energy product managing their consumption throughout the summer cooling season.

Duhan: I want to ask another question about the rebate. You said they get paid a rebate per event. Is it a fixed amount per event or is it a cents per kilowatt hour reduction?

Walter: It is. We pay on a per event basis, per event participated in. Tendril watches customer opt-outs of events and with the Wi-Fi connectivity issues, sometimes those drop in and out. We'd say the customers have to participate in, at least, 50% of the event. Emilie, correct me if I'm wrong on that percentage, but I think it's 50% and they qualify for the per demand response event bill credit, which currently is about a $1.95 per event that we pay for all the events participated in across the season.

Stone: That's absolutely correct it's 50% and we have automated reporting that integrates directly with I&M's billing system to make sure those customers get their bill credit supplied within 24 hours of the DR event.

Duhan: The next question was from Mark Westmore from Asheville. "I heard about potentials for Orchestrated Energy with cooling loads. Has there been any implementation for heating loads?"

Stone: I can take this one. The answer is definitely yes. We ran a pilot with a utility here in Colorado last winter with the goal of reducing overall energy consumption. We were actually running on both gas and electric heating systems, so we're pretty excited to have that launched.

We also are currently in contracting for some new programs coming up this winter. One is focused exclusively on gas demand response, both on thermostats and hot water heaters. The other program is in an area with really high electric heating penetration. We're going to focus on electric DR and eventually electric TOU. I feel like like we are an untapped resource, but definitely something that we are starting to pursue.

Duhan: What are some of the lessons learned around customer experience and messaging from this program?

Stone: I can take this one, and Jon, I'd love to have your thoughts as well, but we've definitely learned a lot about how to message DR programs and EE programs over the last three years. Tendril has worked very closely with I&M's marketing team to figure out, what are the best touch points, what are the levers you want to pull, depending on whether your goal is to increase number of participants or whether your goal is to have high quality participants who are going to deliver high load shed, for example, or a high load shift.

One of the major lessons learned is reducing the friction to get into the program and to get your rebate. A lot of legacy programs have a manual rebate processing capability. We found that anything that we can do as a collective team to reduce that friction and reduce the time it takes for the customer to get their rebate, be it through a marketplace or a third party rebate fulfiller. Those are some different options that are out there to reduce that friction and make a customer happier as they go through the program.

Another one is really around offering multiple thermostat brands. So, this is a little bit of a Tendril pitch to doing the aggregator approach as opposed to going with individual thermostats. You can allow customers to participate with the devices they already have, maintaining customer choice that they feel like they're in control of the device–they're not being told they have to buy a specific one in order to participate. That seems to be really great in driving customer's satisfaction and just getting more people in there for available load shift.

The last one is really about how you talk about the program. Making sure it's clear to customers. Most customers are not energy wonks, like the folks on this webinar. So they're not necessarily going to understand right off the bat the differences between an EE optimization and a DR optimization. We want to make sure they fully understand what's happening each day, understand that they are in control of the device still and understand what the added value is and the continuing value is for participating throughout the summer.

Walter: I might add that from a customer experience perspective and as a utility obviously, in the demand response events if customers opt out of the events, that's an indicator. So, we watch those metrics pretty close and Emilie alluded or stated before that that opt out rates have been pretty low during demand response event days, which has been a terrific outcome of the program.

But then also, we worked really hard up front recognizing that how difficult it is to get to scale with smart connected home technology and customer acceptance of new technologies and the potential for being viewed as well, "I&M's just Big Brother managing our thermostats and we don't know what they're doing," or, "are they listening into us?" All that stuff that goes with that smart home technology.

So that was really a strong consideration that we wanted to watch and customer acceptance of the technology, at least, in I&M service territory, customer base has been good. We were pleasantly surprised with the level of enrollment, but we have recognized, as well, that we're probably at the point where that Emilie talked about reducing that friction to make it easy for customers to trust the technology and understand what's going on so that we get more scale out of the program and we get large enrollments. That's a critical aspect in customer experience as well.

Duhan: I have one last question. What are some of the unique characteristics of Orchestrated Energy versus other thermostat control options?

Stone: That's a great question, Laurie. What we are really trying to achieve with Orchestrated Energy is driving customer satisfaction while meeting utility load management needs. Imagining the personalized thermostat schedules that we can dispatch for devices where we're able to control to that level. Not specifically in IM Home, but for some other programs. This could also mean deploying Rush Hour Rewards with Nest or an Eco Plus for ecobee going forward.

We're really trying to just help utilities manage their load profiles, however they need to do that. So, is it energy efficiency, is it TOU, is it demand response, while also making sure that the customer is always in control, is always comfortable and is seeing continuing value for participating in the program.

Walter: Just to close, with Orchestrated Energy and IM Home, the unique characteristics it's continuous management and pre-cooling. Those are the unique characteristics over just standard thermostats setback programs and it's continually engaging with the customer and having their trust that you're doing the right thing for them from our utility perspective.

There's several unique characteristics of the program, but those just highlight a few and Emilie is absolutely right and correct that maintaining customers satisfaction and being able to achieve higher utility load reductions is critical to the program. We've been pleased with the success so far and the partnership, what we've had with Tendril.

The conversation above is from a webcast recording at https://bit.ly/318H2N3

Program Pacesetters

Pacific Gas and Electric Company and Olivine for Excess Supply Demand Response Program

Presented May 23, 2019

The Pacific Gas and Electric Company (PG&E) Excess Supply Demand Response program (XSP) demonstrates capabilities of demand-side resources to consume or decrease load as a service to the grid to address intermittency due to oversupply of renewables generation as distributed generation accelerates. The California PUC Load Shift Working Group noted in 2018 that the XSP was the only existing load shifting participation model. Designed to capture the full value of flexible resources to the grid it has been incorporated into initiatives across various consumer types including the California Energy Commission EPIC Total Charge Management project, PG&E's Electric Vehicle Charge Network Load Management Plan, and the Pittsburg USD School Bus Renewables Integration Project.

In 2018, events were triggered using PG&E-developed excess supply forecasts. Of the total number of dispatches in 2018, 221 of the dispatched hours aligned with the CAISO's reported renewable curtailment hours for 385 MW of consumption. On average, participants in the XSP can expect eight dispatches per month. Regulatory efforts have already begun in California to develop new models of participation for resources that can respond to load increase dispatches and lessons from the operation of the XSP have already gone on to inform these efforts. The XSP is the first step of what is to come with regards to developing participation models that can fully utilize resources with these flexible characteristics as a service to the grid.

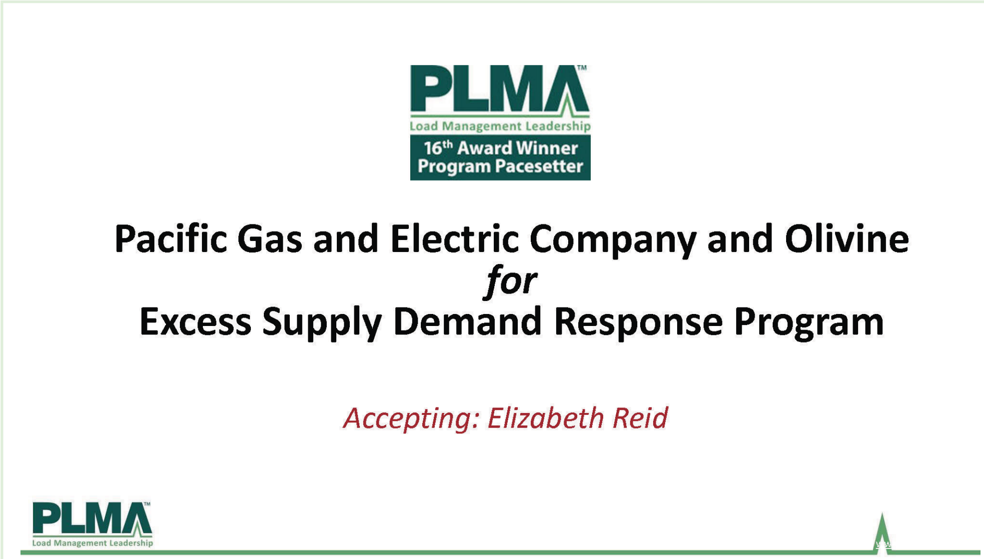
Dialogue transcript:

Paul Miles: Today I am pleased to be joined by some of our Program Pacesetter Award winners, fresh off our recent conference in Minneapolis just last week. They are Jonathan Burrows and Elizabeth Reid. Jonathan is an expert program manager at PG&E, and Miss Reid is actually the CEO of Olivine. Before we get into the Q&A session, I'm going to turn it over to Jonathan to further introduce himself, and talk a little bit about the program, and followed up with Beth.

Jonathan Burrows: My name is Jonathan Burrows, and as Paul mentioned, I'm with PG&E. I'm program manager for the Excess Supply Program here at PG&E, as well as a couple of other demand response pilot programs, and very, very excited to be here with Beth to talk. I really appreciate the recognition from PLMA, and it is unfortunate that I was not able to make it to Minneapolis last week. Fortunately, Beth stepped in and was able to be there to represent the pilot program.

Elizabeth Reid: I'm excited to be here as well. It's really nice that XSP is getting some recognition. I think it's a pretty innovative pilot, and I was happy to accept the award on behalf of the pilot and PG&E.

Miles: Both of you referenced XSP, and XSP is again the program that you referred to as Excess Supply Demand Response program, which again is innovative largely



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because in the DR space, historically we think of a DR 1.0, right? I mean a lot of people use the different analogies, but you know, in the old days, DR 1.0 was, "Oh wow, we have peak load conditions turn things off," whatever that might be. And now we've moved to, and have been actually transitioning for a number of years, but I think this is a classic program that really, really brings us home, to where we're actually both either reducing if necessary, or ramping up, finding loads that we can bring online. And with that, I guess what I'll do is pitch a question to Jonathan. Based on that backdrop, talk a little bit about the genesis of the program, and why it's become more important in California, and probably other places as well. But you know, you hail from California. Tell us a little bit more about your thoughts.

Burrows: In California we've had a long history of offering load management programs going back to, I believe PG&E's first load management program was 1959. At that time there were one or two customers. It's been around... and traditionally it's really been designed for summer peaking load reduction, or for emergency conditions. However, the development and growth of intermittent renewable resources, as well as the retirement of some of California's conventional power plants are presenting a lot of new operational challenges for the grid.

Burrows: Therefore, in addition to traditional DR to address grid emergencies and the summer peaks, in California we've been really looking at new offerings that need to be constructed in order to meet these future grid needs. And more importantly, we want to develop offerings that meet customers' needs. Customers have become much savvier in being able to control their loads, and, rightly so, are interested in being able to benefit from that.

Some of the new DR programs that we're looking at allow customers to bid directly into the wholesale energy market, and/or benefit from being able to provide additional grid services on both the wholesale/transmission side as well as on the distribution side. The Excess Supply program falls into this category by providing a grid service based on wholesale market conditions. And in this case the grid service is really about helping to enable integration of additional renewable generation onto the grid. Because of the increase in renewables, we're seeing that we have an excess of generation, particularly in the winter and spring on the weekends, where we don't have a lot of load from AC cooling, but we still have a lot of sunlight (and thus solar generation) here in California. And with limited storage to absorb the excess generation, we have to rely on alternatives such as the energy imbalance market where we're able to export it out of state. Effectively that's driving prices down. And in fact, during some periods we're really getting negative wholesale prices. So, in essence we're having to pay people, sometimes out of state, to increase their energy usage during those periods.

In the Excess Supply Program, what we're trying to do is enable customers to use their technology to benefit from these excess supply events by increasing or shifting their load to those times of the day when we see negative wholesale prices. That drives the cost of energy down for everyone, reduces the amount of in-state renewables that have to be exported or curtailed, and allows participants to benefit from directly participating in the wholesale market. And you know, Paul, as an example, back in March of 2018, I believe we had something on the order of over 94,000 megawatt hours, of renewables that had to be curtailed or exported from California.

It's not a hypothetical problem. It's definitely something that we're seeing today and will continue to grow. And in addition, the issue of excess supply is not confined to the transmission system. We're seeing localized excess supply situations on parts of the distribution system, for example, in areas where we have a lot of distributed generation and local constraints on how much of the excess generation can be exported out of the area.

Miles: I would like to reiterate the theme, this program both embodies classic DR, but more to the point now, and what is seemingly a bigger issue is this excess supply components. So, with that, how are folks compensated? How do they participate? What sets this program apart from others?

Burrows: At this point, there's no mechanism for behind-the-meter resources to directly bid load increase as DR into the wholesale market. But before I get into that, I'll give a little more background. Demand response over the last few years in California has gone through an evolution where much of it's been wholesale market integrated. To accomplish this, DR has been separated (or "bifurcated") into "demand-side" and "supply-side" programs. Demand-side programs, which are not integrated into the wholesale market, are programs like critical peak pricing programs, which for folks outside of California, are time-varying pricing programs where we tell you when your rates are going to be higher during certain hours the next day.

We also have what's called supply-side demand response programs which are integrated into the wholesale market. These are programs where customers can themselves, if they're large enough, or through an aggregator bid directly into the wholesale energy market. Those customers still pay their full retail bills, but they also can get a wholesale payment for the energy reduction. As I previously mentioned, right now that's only allowed for load decrease, for demand response. We've been working on trying to get this enabled for load increase so that a behind-the-meter resource can bid load increase into the wholesale market. That is in the process being developed with the California Independent System Operator (CAISO). However, it is not enabled yet. So, as a result, for this program, what we've done is try to bridge the gap until there is a wholesale market mechanism in place.

The way the program works is participants tell us how much load they can increase and when (what hours of the day and days of the week) they are available to shift or increase their load. We then look at the day-ahead wholesale energy price and, based on some additional modeling, if we think the real-time wholesale energy price will be negative during the hours the participants are available, we give them a dispatch for those hours.

For example, say tomorrow you said you're available from noon to 5:00 PM to increase your load by 100 kilowatts, and tomorrow from 2:00 PM to 3:00 PM we expect there will be negative prices in the wholesale market, we're going to call you from 2:00 PM to 3:00 PM, and ask you to increase your load by 100 kilowatts.

Regarding compensation, currently, because there is no product for load increasing DR in the wholesale energy market, there is no energy payment from the wholesale market. What we do in the program is we give customers a payment for participation, similar to many of our other demand response programs. And that is, we'll give them a monthly payment based on the number of kilowatts of load increase availability that they have committed to providing when we ask them to. That's how we're compensating program participants until there is a mechanism for them to directly benefit from an energy payment in the wholesale market.

Miles: So, the market's not quite there, you're ahead of your time, but PG&E is basically providing an incentive to participants to get them used to the idea, and you're on the march to further expand this as the markets further develop in the state. That's really awesome. We haven't talked much to Beth about Olivine's role. Beth, can you talk a little bit about your partnership with PG&E, and from your perspective how this is working out?

Reid: We've been working with PG&E on this pilot for a number of years. So, it's not what somebody might call it a traditional pilot where we were just doing a year or two to test out technology. As Jonathan described, I think this pilot was fairly innovative, and some of the details have evolved over a number of years, but PG&E was really very focused on this problem, and so worked with Olivine from the beginning to see if we can create a structure, or a construct to help resolve this problem.

And when I talk about that construct, it's not just technology, it's about regulatory construct, you know, roles, things like that. So, Olivine fills a couple of roles. We would fill one that you might consider a traditional pilot administrator or project administrator, but because of the way this is constructed, we're actually sort of operating as the super aggregator in this program–that's probably the way I would put it–so, that people who are in this program, whether they're, as Jonathan said, large enough individual customers or whether they're coming in under some form of a third party aggregator, we're making it simple for them.

So, they would work with Olivine. We deal with all the contracts with them. We are actually the conduit for the processes of the payments. They use our systems. We send them the signals for any kind of event. And so, they work with us to be able to make all that happen just as they would if they were actually directly in the wholesale market. So that it's not one of those things where the pilot is in a vacuum, and it's not sustainable long term.

Olivine handles enrollments, registrations, what I would call incentive processing, incentive calculations, we are basically an extension of PG&E for that.

Miles: You mentioned you're an extension of PG&E, in terms of signals to participants, can you talk a little bit about the process, and the time horizons that are involved? Are we talking hours and hours? Are we talking day ahead? Are we talking things that happen more frequently to that say in near real time or within an hour or so?

Reid: This is a day ahead type of a program. We're sending signals day ahead, and there's different ways we can do that. We use our systems just as if we were in the market. We work with each aggregation to make sure they get the signals the way that they should. The pilot is basically behind the meter to make sure that, that's clear to people, it's behind the meter. It can be done in all different types of technology.

We are technology agnostic. In reality, not every technology can do this without a lot of other layers of technology, but we're technology agnostic. What we do is work with the different participants to make sure that they're getting the signals in a way they might from the wholesale market, and we use exactly the same signaling methods, as we would in the wholesale market.

We could either signal their cloud directly or we can send them emails. It can be done different ways depending on the situation. We use OpenADR. The idea is to mimic what would happen if the market was actually paying you for this. And the idea behind this pilot is to demonstrate the capabilities of the resources to be able to do it, the reliability of these resources, and to use this as a model to create basically economics so that there will be market payments for this.

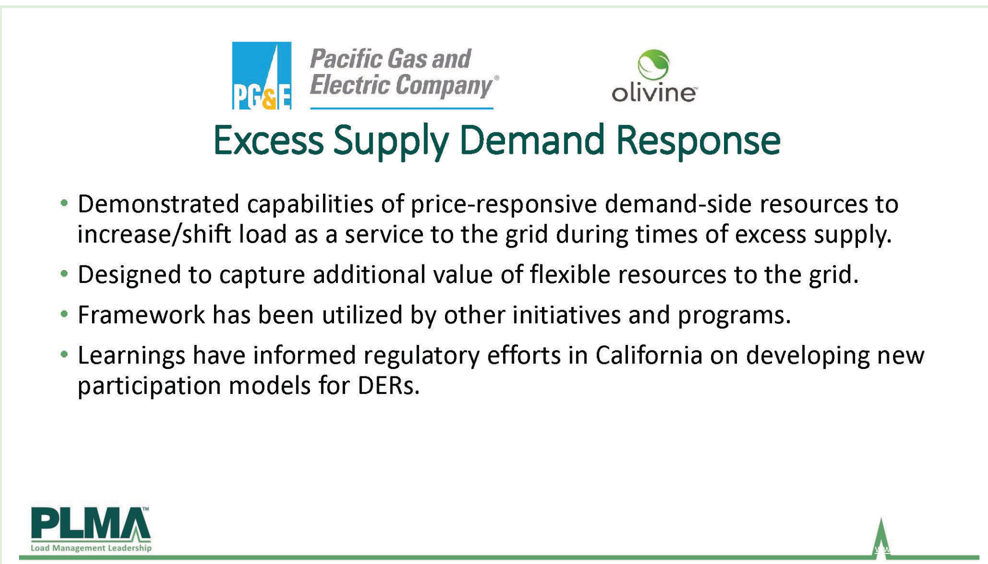
That's one of the ways that we do this. It depends on the specifics, which is one of the reasons we partnered with PG&E, is they wanted to make sure this was a real world type design, and that we could work with each individual participant.

Miles: It sounds like you guys really have put together a good template, and I'm sure you're sharing that with CAISO, and I'm sure they're very impressed and excited about seeing something like this grow over time. Jonathan, so back to PG&E from your perspective, key learnings thus far, where do you go from here?

Burrows: So, what's the next step? The key objective, as I mentioned, was to test the capabilities of price-responsive demand-side resources to increase or shift load as a service to the grid during times of excess supply. What does that grid service ultimately look like, is of course, another big question. This is an ongoing program so we're continuing to learn and make adjustments as we go.

But one thing I think we have found is that participants have been able to respond in excess supply events. That was the big question. If I ask someone to shift their load or increase their load, can they do it? We've had quite a few participants with a variety of technologies, and a variety of customer classes, who have been able to do that. One of the big concerns that customers had were related to demand charges. Some of our rates, particularly for large commercial and industrial customers, have demand charges in which customers not only pay for the amount of energy they use, they also pay an amount based on the maximum demand during certain times of the day.

One of the concerns some participants had was, if I increase my load, does that mean I'm going to have to pay more in demand charges? And what we found is that participants working through their aggregators, or themselves, have been able to really manage that concern. Many of them have been able to modify how they're bidding and their availability, to really not impact their demand charges. A lot of larger customers, who are



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the ones most likely impacted by demand charges, and customers working through aggregators have really been the kinds of customers that have expressed the most interest.

And, what we also found is that, as I mentioned earlier, distribution is key aspect of this. Distribution planning is really important for utilities, especially those that are the utility distribution company (UDC), to make sure that when I ask you to increase the load, I am not doing damage to the distribution network to solve a wholesale problem. So really, more integration with our distribution services is where we're going next.

We're also working on using learnings form the Excess Supply Program to inform development of a permanent market product. In California, the CAISO has something called the Energy Storage and Distributed Energy Resources stakeholder process, which is the forum where work on developing these wholesale market products is occurring, and this work includes making changes to current or developing new demand response products.

The first product is what they call the PDR-LSR, Proxy Demand Resource – Load Shift Resource. PDR-LSR is the first step in allowing behind-the-meter resources to bid load increase DR. And that's in the process of being rolled out. I think that was delayed till next year, late 2020, but that's really the first place we're going to get wholesale integration. We're working with them on that; but, PDR-LSR is initially limited to storage. However, we want to expand that to more than just storage and include other technologies as well.

We're going to continue learning. We're also going to continue to use those learnings to inform various proceedings and see how we can really develop the market and create resources that we can make available to everyone.

Reid: The difficulty with this in the half hour format, is that there's all sorts of high level really big strategic things, and detailed things, and I'm just kind of want to make sure that people understand that some of the specifics is when we say people have been able to demonstrate that they can do this, we're talking about a five-hour block between eight and four. People must be able to provide up to two consecutive hours of load increase.

There's another pilot project that is about supply side part, basically a little bit more traditional DR, it's more curtailment, but it's about wholesale market integration. And so, a particular entity could be in both of those, so they can actually show that they can consume as well as, get the reversed potential plus the curtailment. We are specifically calling day-ahead events, and they're based on day-ahead forecast of the probability of excess generation. So, we're really focused on trying to align this consumption, with the excess generation potential in the market as Jonathan talked about.

And then we're really looking at being as technology neutral as possible. So there is PV energy storage, thermal storage, process shifting, blocks of disabling backup generation, and we actually have quite a bit of EVSE, or you know electric vehicle aggregation in this as well, where we're working with using the structure and the capabilities of XSP, to work with other pilots to sort of reduce the cost to rate payers for some of these pilot programs, both from the utility as well as commercially, but being able to test out capabilities within this design. And there's quite a bit, I mean we actually have the PG&E electric vehicle charging network load management plan, is actually combined with this XSP. So, I wanted to make sure that people kind of had a color of the details and the breadth while we're talking.

Miles: I did see a couple questions around batteries, but you mentioned technology agnostic, and I'm guessing at this juncture... You know, again, you're still at the 10,000 foot level, you haven't come down to tree tops. So, I mean if batteries are participating–they are–but they're again behind the meter, and again, I think you were very clear on that. And also, there was some questions around in California against a little unique in the greenhouse gas reduction space. Does greenhouse gas reduction at all play into this, or a will it at some point?

Burrows: It does, but not necessarily directly. For a lot of what we're doing, the impetus and an underlying driving factor is greenhouse gas reduction to help the state meet its GHG reduction goals, but GHG reduction is not necessarily the direct goal or metric for many of these individual initiatives. Also, while the intent may be GHG reduction, sometimes this is not the outcome. In fact there is a growing concern that, if I'm a load serving entity, and I'm purchasing a lot of renewable energy in my portfolio, it may not be as clean as I thought. For example, if I have procured 100% of my annual energy needs from renewable resources, that doesn't mean that I'm using 100% renewables to serve my load. If I'm not using the energy at the same time of day that it's being produced (for example because I don't have load at that time), I have to sell it to someone else that can use it during that period. I then have to substitute the renewable energy I didn't need with energy during the time when I do need it, which may or may not be as clean. As a result, I'm actually still potentially relying on a lot of non-renewable generation to serve my load during those times when those renewables are not producing, such as during the evening peak.

However, California is somewhat unique when looking at our wholesale energy prices. Some studies have shown that wholesale energy prices actually are a fairly good indicator of the GHG emissions from generation on the margin. So higher price wholesale energy is a good indicator of higher emissions and lower or negative wholesale energy price is a good indicator of lower emission generation, such as renewables. Since we're trying to reduce excess supply, or fill in the belly of the duck curve that people have heard about, and the duck curve is reflected in the wholesale energy market, by shifting demand based on the wholesale energy price we should be, in effect, driving GHG reductions.

Reid: We do sort of look indirectly at how much GHG that we're reducing. But the focus here is to make sure that this is actually a reliable resource that also contributes to the reduction of the greenhouse gas, and that there's an economic path for these types of resources. As Jonathan mentioned, there was a lot of effort working with the ISO, and the CPUC from this pilot, and the other utilities are taking learnings from the pilot, but to actually create a mechanism where there's a value stream associated with this consumption, because right now there isn't.

And we've come a long way, now there's a lot of attention on this to be able to create that as Jonathan said, next year we're going to see a lot of changes here in California. There's actually a payment coming through in order to align this. So that's the way we're focusing this, if it's not going to end up with a sustainable market, then we're going to have a problem. The way we're looking at the pilot is to try to make sure that all those pieces fit together.

So, it does indirectly, but we do not measure the success of the pilot, or trigger it based on greenhouse gas emissions. We are definitely focused on the excess supply, the over generation.

Miles: I think that's abundantly clear over the course of the conversation today.

The conversation above is from a webcast recording at
https://bit.ly/2t74DRC

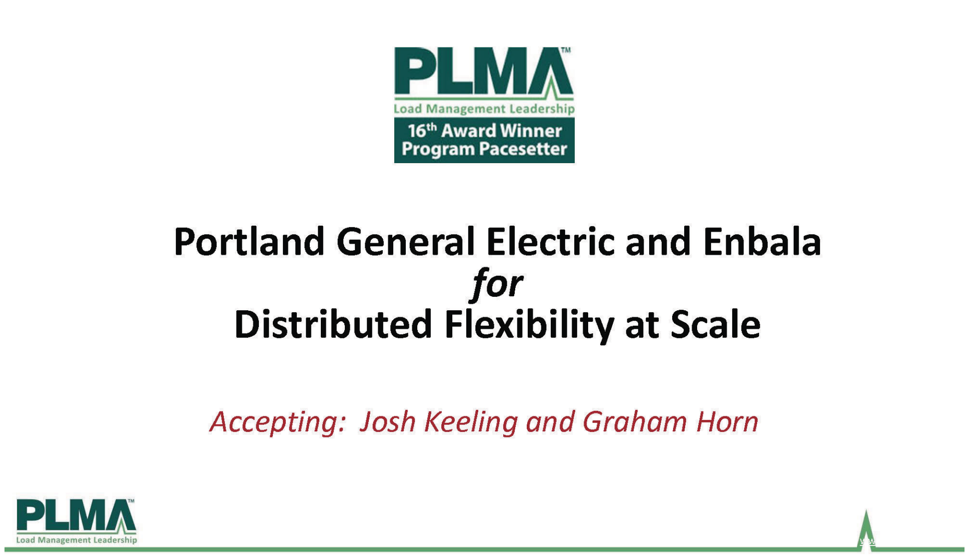
Program Pacesetters

Portland General Electric and Enbala for Distributed Flexibility at Scale

Presented June 13, 2019

Portland General Electric (PGE) has created a technology agnostic, interoperable virtual power plant (VPP) in collaboration with Enbala that enables PGE to offer control, optimization, and demand management of an entire fleet of DERs across various customers, vendors and programs. This multi-program-multi-vendor-ecosystem allows for the customization across DER asset-types, location, participation schedules, and service offerings, while providing visibility into, and integration of, data in an approach that is scalable, sustainable, futureproof, and customer-focused.

PGE's VPP now includes over 100 large industrial loads, large commercial loads, and small commercial loads; over 150 commercial smart thermostats, and nearly 3,000 multi-family smart water heaters. The VPP is currently integrating a combination of solar, storage, and smart thermostats at a Fire Station with the City of Portland to demonstrate a turnkey microgrid solution in partnership with Powin Energy. PGE is also rolling out a Time-of-Use (TOU) Program and Peak Time Rebate (PTR) Program that will target 58,000 customers in 2019.



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Dialogue transcript:

Paul Miles: Today's discussion will be around a recent Program Pacesetter Award through the PLMA to the folks at Portland General Electric, in collaboration with Enbala. I would like to introduce both PGE's Josh Keeling and Enbala's Bud Vos. A little bit about Josh, he is the Manager of Distribution Resource Planning at Portland General Electric, and Bud Vos is the CEO and president of Enbala.

The program that we're discussing today is a technology-agnostic, interoperable virtual power plant (VPP) PGE that created, with the support of Enbala and others, to enable them to control optimization and demand management of an entire fleet of DERs across various customers, vendors, and programs in their territory. This multi-program, multi-vendor ecosystem allows for the customization across DER asset types, location, participation, schedules, and service offerings, while providing visibility into and integration of data, using an approach that is scalable, sustainable, future-proof, and customer-focused. And with that, I'd like to turn it over to Josh to kick off the discussion. Josh, tell us a little bit about the program, and we'll get into some Q&A following your description.

Josh Keeling: Sure. Thanks, Paul. Yes, I'm really excited about this. It's really funny timing. We actually just dispatched our first event of the summer season yesterday. So, I was just looking over the numbers while I'm on the road right now, but it was nice to see things are going well, and it looks like the program over-delivered in the last event, so that's always great to see.

A lot of people talk about VPPs and mean a lot of different things, but the big focus for us was taking a sort of ecosystem approach. That meant really being inclusive to a lot of different ideas, technologies and methods, and meeting our customers where they are. This makes things kind of hard on the implementation and IT side sometimes, but I think it's well worth it. So, that's been a lot of approaching assets and saying, "Okay, well, where we can use open standards, that's great, and we will, and where we see technologies that are compelling but maybe don't fit into that, that's okay too, and we just need to make sure that we're delivering the right value."

Enbala's done a great job helping us to give a lot of options to our customers, particularly in our C&I program, where we have... I can't remember all the different nomination options. The customer had like four different windows and three different notification times, and nominations that change by month, and we operate our VPP in both summer and winter. They use both automated and non-automated, and different baseline methodologies. It's really been successful, by taking that sort of open-ended approach and really thinking about outcome instead of specific solutions that we're seeing really great uptake with the program.

Miles: That's a good overview. I would like to drill in just a little bit into something you said. You talked about open-ended and technology-agnostic in your description, and you mentioned that Enbala is helping you out. Exactly what does that mean? Some of our participants today had sent in questions around this open-ended interoperability. Is it come one come all? How are you guys addressing pretty much anybody who wants to get into the program in terms of providing a widget, if you will? Or, is it really that simple? And I know you mentioned that from an IT perspective it's challenging, but can you drill down just a little bit more on what that looks like?

Keeling: Yeah, sure. It's interesting. I'm out in San Francisco at the OpenADR Symposium, and yesterday there was a lot of good conversation about how standards play there, but also how standards interact with proprietary systems. Varun over at EnergyHub used a good term that I like: It's not that they're proprietary; they're just custom systems.

For us, the big thing has been to make sure that we can always say yes to the customer. In the past, when we've run programs – particularly on the commercial/industrial side – they've been very specific and sort of designed from an inside-out perspective. And here, we really took the opposite tact which was to ask the customer what they can do, or what works best for them, and then figure out a way to make it work. I touched on some of that in terms of how the structuring works, but in terms of the technology, we use open standards where we can, so you know, we've used Modbus in a lot of cases, we use CTA-2045 on the water heater side in some cases, and then sometimes there's a custom solution that delivers the results, then we're willing to make the changes in our program and do those custom integrations.

What's been helpful there is taking an agile approach to the roadmap and saying, "Okay, this is what we're getting in terms of customer feedback," and opportunistically jumping on projects where they come up. For example, with the microgrid project that's mentioned here, there was an opportunity with the fire station that came up through our renewables program, and it seemed like a great opportunity. There, they were interested in doing solar plus storage, and we were able to partner with a local firm, Powin Energy, on the energy storage side, and then through that program discovered that there were some pain points around some of our thermostats in all their other fire stations, and we were able to incorporate that as well.

What's important is taking the customer feedback and finding out a way to make it work best. A good example of where standards come in is when we start looking at things where there's a more diverse set of technologies, and maybe it's a little bit less stable, say like in EV charging. That's where we start to say, "Okay, well maybe we really do need to work within a standards framework a little bit more strictly." But, if there's a technology vendor out there who doesn't adhere to the standards that our customers are really happy with, we're going to find a way to make it work.

Miles: That's very interesting and does put things in perspective a bit. You talk about your large C&I customers, you mentioned and touched on smart thermostats, and I'm going to assume that most of these are web-enabled. But you talk about the multi-family hot water heaters. Are these off-the-shelf grid-enabled units, or did you have to do something so that they could communicate and participate in the program?

Keeling: Today, we've been working in retrofit, so the vast majority of the hardware we have out there right now is with Aquanta. They've been a great partner as well, and really collaborative between CLEAResult, who's our program implementer, Enbala on the VPP side, and Aquanta on the hardware and head-end system. But we've also been doing some work with CTA switch vendors. We're working with SkyCentrics as well. And then also, having a relationship with those, this is through the property managers, wherein, when those units fail, we match them up with A.O. Smith tanks, find out the incremental cost of a smart tank, and then put in the CTA module.

That's just beginning, that's sort of a vintaging. We also do have a CTA program that we're doing as part of the regional pilot, and we're having conversations there about heat pump water heaters that are CTA-enabled. And we're looking at, with Enbala, in terms of roadmap, when we start to integrate those into this platform as well. Because they're CTA-enabled, it's pretty straightforward, because our CTA integration's already done.

Miles: It sounds like eventually, in a perfect world, everything would be CTA-enabled. Slipping it to the other end of the spectrum, what type of offers, or how are you working with the large C&I folks, for them to participate in this program?

Keeling: We have a pretty open-ended tariff that we offer. If you think about it from a business model perspective, we actually sort of show up as the aggregator here. In some sense, Enbala provides the technical aggregation from a software and optimization perspective, and then we, from a sort of contracting perspective, working with the CLEAResult folks on the engineering and field operations customer acquisition, but PGE actually acts, from a contractual perspective, as the aggregator here.

The reason for that is because it gives us tremendous flexibility. The dynamics in the Northwest are really complex with respect to load. There are peaks happening all year; we just had a pretty serious-looking peak that happened in March. Or, not a system peak for us, but a grid event that happened in March. So, things are changing, and for that reason it's really important for us to have flexibility.

The other reason for that is so that when we meet with a customer, we're able to find an offer that's palatable to them, no matter skeptical they may be. So we give the customer options on how to participate, like day-ahead notification, giving them potential for opt-out bids, allowing them to do manual demand response, or something as simple as a turnkey smart thermostat., Customer options been a really important part of the success.

In terms of the technology that we're enabling, we don't have a lot of large industrial customers, or national accounts, because of the direct access environment here. We have partial deregulation in Oregon, so we've been really working with municipal pumping, refrigerated warehouses, things like that have been really successful.

Miles: Let's talk a little bit about going back to the beginning when this was a concept, and you were basically building it and borrowing support within the organization. Was it an easy ride, or did you face some hurdles along the way?

Keeling: It was a process. The thing that we did that has really helped build a coalition internally, and with our commission staff and stakeholders, is to treat this as an iterative process, provide the vision, and then sort of bite off small bits and chunks, and iterate. Also, in the past our DR programs didn't have a lot of engagement with our power operations folks, and when we went into the redesign phase of our C&I program, we did a lot of customer research. But then we also went to our power operations and treated them as if they were our customer too, because they are in a lot of ways. We spent a lot of time saying, "What are your needs, how much more valuable is this service versus that service, how do you use day-ahead resources versus real-time resources." I think that motivated a lot of the approach, and the choice to work with Enbala was really motivated by what we found in that regard.

Miles: That's a very important item that you bring up. It sounds like you were able to convince folks that what you were proposing was real and could be used to support some of your resource needs, and that's always important. How many folks do you have that manage this program today?

Keeling: It depends on how you define that. We have a dozen or so program staff. Then we have folks who are not dedicated to the project, but are with allocated folks on the power operation side and the grid operation side, so we've been the balancing authority, particularly as we were just about to implement our ADMS, and there'll be an integration there with this platform. And then, we are actually in the process now (which I think is really a sign of where things are going) of hiring a dedicated solutions architect on the IT side, which is really exciting because in the past, that's sort of been ad hoc, as needed.

Miles: Sounds like a very exciting progression, and you obviously have support and you're getting resources that you need, and you'll have to keep us posted. As we transition, Bud Vos has been very patient, and I might point out, he's halfway around the world on assignment, and we thank him because it's very early in the morning where he's at. Bud, why don't you offer a few comments about your firm, and we'll get into some Q&A with you and bring Josh back in.

Vos: I think Josh has very graciously touched on a couple of important points about the Enbala platform and what we've been able to provide, but I really want to point out that the real winners here are the customers within Portland General and obviously, with the leadership of Josh and Portland, they wouldn't have such a great program. And I think that it's really a testament to the fortitude, if you will, that Josh has experienced within the firm, but also outside in the ecosystem, so to speak, to put forward such a bold effort.

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One of the key aspects of our platform is the ability for us to aggregate all of these different types of things, and it's a big change in the world of demand response, and what we think of as moving towards demand flexibility, and ultimately virtual power plants, is the need to incorporate literally an entire ecosystem of both devices and customer types, and also systems that don't just represent load, but also systems that represent generation, such as storage and solar. And you have to bring all of those things together, and that's one of the key elements of our platform, and one of the key components of why Enbala exists today.

Miles: Moving a little bit away from Portland General's current experiences, what would you offer up about what this looks like across not only the U.S. but worldwide, relative to Enbala?

Vos: I think that virtual power plants have become a very vogue term, so to speak, but in the North American context, we think of them predominantly as this transition of demand response. Outside of North America, however, we're seeing a much broader transition to virtual power plants, mostly around energy trading and wholesale markets. All over Europe – where we're actively engaged – we're seeing very mature energy and ancillary services markets that are emerging. Other places around the world, such as where I am in Australia right now, due to the high penetration of renewables and extreme amounts of variable renewable energy on the system, they need to have not just wholesale markets, and these types of devices at the grid edge interacting with those wholesale markets, but truly the need for them to become fully integrated with the power system. You're seeing large amounts of, say, hosting capacity on distribution feeders of solar. As a result, you're looking at how do you use these grid-edge systems, not just loads, but again storage and electric vehicles and other types of resources, to help balance the power system itself.

One of the biggest challenges that I think we have in the distributed energy marketplace, broadly, is how do we do both? How do we satisfy the needs of the distribution network while at the same time allowing these assets and customers and retailers to participate in wholesale markets? In a place like Australia, we're seeing the emergence of that actually occurring, where you're doing this kind of optimization for both parties. It's a really complex world, but it's an exciting world, because it's the way that we get to a decarbonized future, and by decarbonizing the power grid, you need to have the grid edge fully engaged and operating with the system, not fighting against it.

Miles: When we talk about a virtual power plant, what does that look like, and what does it look like in North America versus say, you had mentioned, things are proceeding aggressively down where you're at in Australia?

Vos: I think there are three characteristics of a virtual power plant that characterize it. The first is multi-asset systems. You have all kinds of different types of devices that are now connected into the system. So again, going from traditional load type devices, many of which Josh was talking about, but also starting to branch out and bring in other types of devices, such as storage, the integration of PV along with that storage, and then perhaps even electric vehicles. That's the first characteristic; you have this huge ecosystem of systems that need to come together.

The second characteristic that I think is important, is that this is more of a real-time system. You're moving away from the event-based kind of older demand response type approaches, and you're moving more towards the direction where it's a system that's live and connected all the time that you can now flex up or down from a power perspective. That is what is really differentiating between what we might think of as traditional load control and now virtual power plants. The good news is, is virtual power plants can still do the types of things that we need to do in demand response and capacity, but you can now do them in real time.

And then the third characteristic when you bring it all together is the ability for that virtual power plant to essentially play in multiple markets at multiple times. Now, of course that's dependent upon the market rules. It's dependent on the types of grid services that you need to provide. But you have the capability with both the connectivity and the assets in the field, and the software layer sitting above it, to now be able to do things such as helping the customer optimize their energy demand while also managing peak demand for the utility. And you need to be able to do both, but you can do both because you're fully connected. You have a real-time system, and you can run the algorithms and optimization that brings it to bear.

So, these are the three really important characteristics, I think, that we think about in virtual power plants. Again, that multi-asset piece, the real-time connectivity components and the ability to run real-time optimization, and then the third piece, which is being able to run multiple grid services at the same time. Now of course, when we deploy our technology around the world, Paul, we see it used in different ways, because the markets are different – the rules are different – but these are kind of common characteristics across all of them, in North America, Europe, Australia, Japan, and a few other places around the world as well.

Miles: I'm going to pull Josh back in as we sort of move towards a close, and basically, return back to Portland General. So, you won the award, and there's been some good discussion here today. What's next? And Josh, I'll ask you first, what do you see down the pipe in terms of the next stage of the VPP effort, and depending on what are your thoughts, we'll bring Bud in.

Keeling: I sort of separate it into two tracks in terms of where we're going. One is on the customer side, and one is sort of back office stuff.

On the customer side we are right now going through the technical work to integrate electric vehicle charging within the business and residential side. And I think that's likely to see a place where you start seeing us implement more sort of OpenADR type approaches, just because of the success we've seen with some of the Californian utilities in particular. Southern California Edison has done some really good work in that regard.

And then, energy storage, so we actually, we have some energy storage that's coming in through energy partners today, just through a standard demand response program. The difference is that I think we need to start adjusting those tariffs in such a way that we're compensating them for all of the services they can provide, similar to and relevant to what Bud was talking about, what's happening in Australia and other places. And also, just to be able to give the opportunity for end uses that can provide those services as well. Pumps are a great example, and I know Enbala's done some work in this regard, say in the PJM market, but municipal pumping is a great example of a resource that can do a lot of the services that a battery can do. So, we need a way to give customers adequate compensation for that.

On the back office side, a lot of the focus is on incorporating into our ADMS, and a lot of that's going to happen through our smart grid testbed project, which is some targeted projects on specific substations. And then, also, incorporating our learning and our capabilities into our distribution resource planning effort, particularly around, say, interconnections, and really integrating contractual requirements that we have as a part of interconnection into our VPP, so we can just automate that process, and make sure that those are included there. And then to understand from a resource characterization perspective, the operational characteristics that we see in the VPP. What does that mean for how we plan our system so that we can start to look at things like non-wires alternatives, et cetera.

Miles: Bud, any final comments before we shift towards the end of the program.

Vos: The only comment I'd make, is I completely agree with Josh, and I love his phrase "meeting customers where they are." That's the way we think about it as well, and we don't think about it just from the context of the end customer, but also our partnership with our customers.

We're on this journey together with Josh and PGE, and it's been a very collaborative effort to get to this point, and all of the things that he just talked about – EV charging, EV storage, or energy storage, all these other devices, pumping loads. We look forward to continuing to broaden the program, continue to bring in new features, and continue the journey with him.

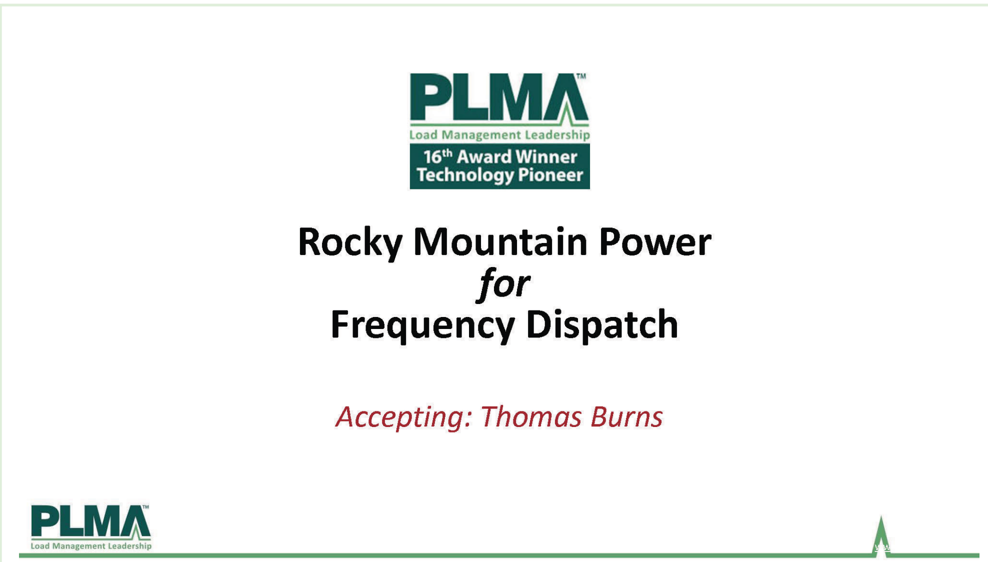
The conversation above is from a webcast recording at https://bit.ly/37xydi4

Technology Pioneers

Rocky Mountain Power for Frequency Dispatch

Presented August 15, 2019

PacifiCorp demonstrated that Demand Response (DR) resources can be used to deliver GridScale Fast DR to meet frequency dispatch and BAL 3 requirements. This project demonstrated that the Cool Keeper system could be used in an additional capacity with very tight control response. PacifiCorp designed and implemented the automatic dispatch of residential customers enrolled in the Rocky Mountain Power Cool Keeper program utilizing Eaton's two-way devices and Yukon portal to respond to frequency dispatch signals. To comply as frequency dispatch, the resources must immediately begin providing support once dispatched and be fully activated within 50 seconds from event detection. The BAL 3 measurement is a performance curve during this resource dispatch period. The solution resulted in an average of 64 MW of BAL 3 resources and over 100 MW of load drop across several events during the 2018 summer DR control season. Performance was measured and calculated using two second system metered data collected by the PacifiCorp Energy Management System.



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This innovation is a grid scale solution using fast-acting residential DR resources to support the bulk power system. Utilities currently use generating resources to perform this function, but as plants are retired or begin operating at lower levels additional balancing resources are required. The Cool Keeper system provides approximately 200 MW of operating reserves to the system using over ~ 100,000 residential AC resources.

Dialogue transcript:

Michael Smith: Today, we'll be hearing about Rocky Mountain Power's frequency dispatch initiative which is one of our Technology Pioneer Award winners at the 16th PLMA Awards this spring in Minneapolis. Today we have joining us, Shawn Grant from Rocky Mountain Power, Thomas Burns from Pacific Corp, and Joseph Childs from Eaton, who are each going to tell us about their role in the project and how the project progressed. With that, I'll pass it to Shawn to introduce the team and tell us about the project.

Shawn Grant: I'm Shawn Grant, I've worked with Rocky Mountain Power since 2006, and I've worked in various roles within the energy industry for over 25 years. I'm currently a Senior Customer Solutions Program Manager for Rocky Mountain Power and have responsibility for behavior-based energy efficiency programs, electric vehicles, agricultural load management, and residential load management. I currently manage a portfolio of over 400 megawatts of demand response throughout Idaho and Utah.

Thomas Burns: I'm Thomas Burns, I am the Director of Energy Supply Management Operations and Reliability for Pacific Corp. My responsibility is I am the balancing authority for Pacific Corp East control area and the Pacific Corp West control area. Specifically, I'm responsible for the BAL standards as far as the NERC functional model goes.

Joe Childs: I'm Joe Childs with Eaton and I'm Senior Manager of DR Strategy and Business Relations. I've been working in the DR industry since last century under a few companies and have been with Eaton through acquisitions for 16 years. I've helped utilities with residential, commercial, and industrial solutions.

Smith: Shawn, Tom, would you like to tell us a little bit about the project, just to frame our discussion?

Grant: Rocky Mountain Power has been operating a residential and small commercial air conditioning demand response program in Utah in the Salt Lake Valley for over 15 years. The service territory that we operate this program is kind of geographically limited. Our program is limited to basically 50 miles North and South of Salt Lake along the Wasatch Front Mountain range. Our load management program is administered by Eaton and Franklin Energy. We currently have over 108,000 air conditioners enrolled in the program and our program utilizes Eaton's Yukon portal and their two-way communicating load control receivers. PacifiCorp's demand response program may be a little bit unique. PacifiCorp's Energy Supply Management team utilizes this program or resource to effectively managing the electrical grid throughout the West.

As you'll note, I didn't mention that we use it not only for peak load shaving but we use it to effectively manage our electrical grid. Our load management program, under the right conditions, can be called upon 24 hours a day, seven days a week, throughout our program season. For example, this summer we had a load control frequency event that occurred at 1:00 am during the summer. This particular event only occurred for five minutes.

This summary provides a brief overview for how our program operates. I'll turn the time over to Tom and he can elaborate more on how it's used from his control side and some of the things they do within energy supply management.

Burns: From a planning and implementation perspective, my primary responsibility is delivering energy to our customers reliably. My very close second responsibility is delivering that reliable energy at the lowest net power cost possible. With that dual mandate, we are continuously looking for tools that will deliver reliable energy and do it as cost effectively as possible. That becomes increasingly challenging as we have more and more renewables on the grid.

There is more uncertainty introduced into the grid. There's the retiring of traditional thermal resources that have provided things such as frequency response, contingency response so the demand for those resources is increasing, the supply is decreasing, that's not a good situation. In working with Shawn's group and Joe from Eaton, we kind of just took an inventory of what we had. We had this very powerful demand response program that was very good for energy products. It could peak shave.

Now, that's good but we looked at it and we said, "How can we make this better? How can we improve upon this very powerful product and get our customers more reduced cost?" We came to the conclusion that if we were able to apply this as a reserve product, we could use that and our resource plan for a larger number of megawatt hours without actually deploying the program.

This resulted in a lower net power cost with actually a decreased burden to our customers because we were interrupting them less often. We were deploying the Cool Keeper Program less often, but we were utilizing the capacity, the ability to curtail the program in our resource plan. That allowed us to integrate more renewable resources, maybe deploy more economic resources. There was a considerable amount of team effort involved in this because it wasn't just my group or Shawn's group, we also had to incorporate extensive inclusive of our IT team as well as making sure that our CIPS group, critical infrastructure protection systems group, was included to make sure that everything that we were doing abided by those standards.

Overall, I'm very pleased. I continue to be impressed with the work that Eaton does and the work that Shawn continues to do. These programs just keep on improving and they are increasingly important as the portfolio of how we serve our customers changes.

Grant: As we were looking to evolve traditional demand response, one of our primary concerns was customer experience. How can we provide a customer centric program in addition to developing a program that provides benefits to our customers? As Tom mentioned, one of the primary purposes , is to lower net power costs, which involved working with the vendors, coordinating with multi-departments throughout PacifiCorp, and utilizing technology, we were able to develop this program which allows PacifiCorp to have flexible resources.

Childs: I'll provide a brief summary on how this works from a technology standpoint. Traditionally, DR resources are deployed from an operator sitting at a control screen and activating an event. For DR resources to work effectively as reserves and frequency dispatch, they have to be part of the control infrastructure of the utility. Pacific Corp has invested time and energy in their Energy Management System (EMS) which includes advanced applications including unit commitment, contingency analysis, AGC, etc.

DR Resources have to be registered into the EMS and require a live forecast so that the advanced applications know what resources are available and how much they can dispatch. For Dispatch, the EMS sends a trigger to the DRMS to perform automatic control without operator intervention because of the time constraints.

From the field communication side, we're using an RF mesh system that provides a secure communication channel to every field device. As Shawn said, we have 108,000 devices out in the field. The key communication feature is a broadcast message capability. It is a single message that each device can receive instead of individual messages addressed to a single device. This feature minimizes the communication time to activate the devices.

Smith: Let's move to some of the pre-submitted questions here. What is frequency dispatching and how does it relate to under-frequency load shedding, which some may be familiar with?

Burns: Frequency dispatch satisfies BAL Standard 3. It's a precursor to under-frequency load shedding. We always hope that we never have to deploy under-frequency load shedding. Specifically as it pertains to Cool Keeper, inside our EMS, our energy management system, we have a calculation that's running that monitors frequency. It has a scan cycle of every four seconds. When the calculation runs and it tacks a change in frequency over a given amount of time, that triggers the response where we have determined that there is a high probability of a frequency event occurring on the interconnect.

By frequency event, that can be anywhere in the Western interconnect, it does not have to be Pacific Corp specific. When that calculation triggers, it takes two scan cycles to detect that. The third scan cycle sends a signal to the cool keeper portal. The cool keeper portal then sends that signal out to the 108,000 devices that are out in the field, so, we are getting near 100% response of available load within 50 seconds from the Yukon system. We burn through eight seconds on our side just having that calculation running and the detection during those two scan cycles.

For frequency response, we take the average deployed over one minute. That creates a change in our area control error, and that change in the area control error satisfies the frequency obligation of Pacific Corp to the interconnection. That's a long answer to a fairly simple question. Frequency response comes prior to implementing under-frequency load shedding.

Smith: What sort of regulatory coordination was needed to allow for fast dispatch of these resources for this use?

Grant: We feel like we have a very supportive regulatory environment in Utah where we have a collaboration group to address these issues. One of the biggest coordination efforts was educating our regulators and stakeholders on exactly how a frequency dispatch would operate and potential impacts to the program.

As Tom was educating us on frequency response and potential issues, there can be very complicated terminology and for those who are not involved in these types of programs on a day-to-day basis, it can be confusing, therefore we held working sessions with stakeholder groups. Tom and I had conference calls, answered questions and responded to data requests to better inform, educate and help our regulators understand the process. Ultimately, in the end we did need to make some changes to our regulatory tariff that went through the normal process which allowed PacifiCorp to have a flexible resource.

Overall, the commission and stakeholders, were supportive of this program. They also recognized the value that this would provide to customers and to the company in the short- and long-term to reduce net power cost and provide grid stability.

Burns: I do have to say that we are kind of spoiled and we are fortunate because our regulators are a very well informed group of people and it makes it very easy to talk about what we are doing, what we're trying to accomplish. They're able to provide us with questions that are very meaningful and we're able to have a very open dialogue with them. Also, I have to give compliments to you because you built up trust over a number of years with our regulators.

We're being transparent, we're putting the customer first. They're at the forefront of everything that we do, the actions that we take, and that makes it easy to get stakeholder buy-in when the whole end-point of our actions is to benefit the customer.

Grant: Right, and that process that we've established, it's occurred over the last decade through collaboration with internal and external stakeholders. The process has taken time and it created foundation for future collaboration and innovation.

Smith: How much is the average residential customer paid for participation in frequency dispatch? In the program design process, how did you determine where you wanted that to be?

Grant: That's a very good question, how does this program financially pencil out? How do you design a cost effective customer program? PacifiCorp currently offers a $30 bill credit incentive for program participants who participate in the program during May through September. If a customer participates throughout the entire season, they can earn $30 for participating. The incentives are paid out in the form of a bill credit. We're currently offering bill credits as a monthly bill credit for customers who enroll or un-enroll during the program, their bill credits are pro rated. Small commercial customers, those who have larger air-conditioning equipment, qualify for a $60 bill credit for program participation. The typical residential air conditioner, for 90% of our program participants, receives a $30 incentive.

Smith: Another questioner here is wondering how is M&V done for frequency response programs and how does it differ from maybe standard thermostat DR M&V?

Childs: First, Frequency Control is very customer centric because we do an immediate shed of all devices that are connected to the system but the duration is only five minutes. Then, to make sure that this resource doesn't come back online and cause an additional system issue, we randomly ramp those devices back into running for over a 15 minute period.

We have a very short duration of a big drop and then the customers AC units return to normal operations. From a customer standpoint, this is about one cycle of an air conditioner. Air conditioners run, depending on how hot it is, for five to 10 minutes and then sit idle until the home needs more cooling. Frequency Dispatch has less impact on the customers per event than the traditional longer hour or two hour events. Pre-cooling is not an option because the events are real-time.

M&V is done two ways. First, this is a pretty big resource, we can get up to 200 megawatts at the high temperature part of the day. The EMS has a real-time status of the system using the meters in the transmission substations that are polled every four seconds. The dispatch office and the EMS receive the real-time confirmation that the system load dropped.

Secondly, we collect runtime from all of the controlled devices and after the event we do an analysis of exactly how many devices received the signal, how many performed and, and how long they shed. With this information we analyze that we're treating each customer fairly with respect to total control time (event and ramp out). We have pre-event and post-event data to validate the MW reduction.

Smith: Shawn, I have a two-part question for you. I guess first, for someone interested in looking at designing this type of program, what are some of the hurdles that you faced in designing and implementing a frequency dispatch? Then also similarly, any key lessons learned when it comes to working in such a cross functional team to achieve this type of program design and implementation?

Grant: I'll try to address that in the couple minutes that we have left. Some of the hurdles that we faced is, and I think Tom mentioned this a little bit ago, were cybersecurity concerns. As all utilities are experiencing today and all businesses, cybersecurity is becoming a real issue. Could our vendor and could the technology, develop a secure solution? The solution was required to have immediate response with basically no operator involvement, could this type of solution be secure? PacifiCorp and Berkshire Hathaway Energy have the highest standards of cybersecurity. The security team over time was able to become comfortable with the solution and confident with the controls in place. Cybersecurity was one hurdle we had to overcome. Technology evolution was another potential hurdle. The basic concept of frequency demand response was not readily available and utilized throughout America. Developing emerging technology requires a lot of testing, trial and error and learning as you progress.

Another hurdle we faced was the perceived customer impact of doing these types of dispatches and doing them at potentially non-traditional times? As Joe Childs mentioned, when we have these events, typically their air conditioners are under control only for five minutes. During an event we are only shutting off their AC compressor. The fan continues to run therefore air continues to circulate cool air throughout the home creating a positive customer experience. Our experience over time has shown, customers aren't even noticing that their conditioner's participating in a load management event. As we've mentioned, we have 108,000 customers in this program and when we call short-frequency events our customers are noticing no impact and customer service centers will receive no inquiries regarding load management events. Maybe with our remaining time I'd like to briefly touch on the cross functionality team challenges with this type of project.

This can definitely be a challenge too. I'm here in Salt Lake, Tom is in Portland, our vendor Eaton is in Minneapolis, and PacificCorp operates under a six state service territory with employees located in different states–that can create real challenges. The key to overcoming this challenge, was developing a clear plan, everyone understanding their role, and everyone being committed to achieving success.

The conversation above is from a webcast recording at https://bit.ly/3aMpNFG

Technology Pioneers

Viking Cold Solutions for Using Thermal Energy Storage as a Grid Asset

Presented September 12, 2019

Commercial & industrial freezers (10,000 to 200,000+ square feet) in the food and beverage, foodservice, grocery, and cold storage industries require massive amounts of electricity to keep frozen food product temperatures stable between 0 and -20 degrees Fahrenheit. These facilities maintain the highest demand per cubic foot of any industrial category and globally spend over $40 billion on energy every year.

Viking Cold Solutions uses thermal energy storage systems (TES) to utilize frozen food facilities in the United States, Mexico, the Caribbean, and Australia as grid assets that enable operators to shed 300-500 kW for up to 13 hours each day. TES systems leverage the facility's existing refrigeration system to store energy in the form of cold and discharge that energy over long periods of time when it is most economical for the grid and the facility operator. These systems have no mechanical components and use phase change material, to absorb up to 85% of the heat infiltration while refrigeration is cycled off, and intelligent controls to balance temperature requirements and energy use. With a levelized cost of energy of less than 2¢ per kWh, many power providers have added TES technology into their efficiency and demand management programs to improve efficiency an average of 26%, help address the variability of renewables, and unlock large-scale demand management opportunities for a fraction of the cost of other storage mediums.

Dialogue transcript:

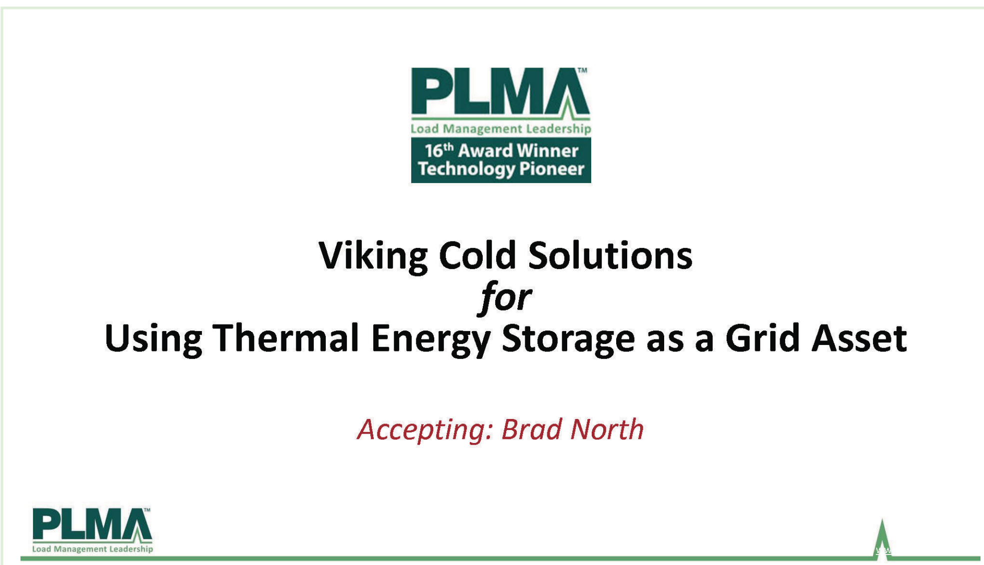
Michael Smith: Today we'll be hearing from one of our Technology Pioneer Award winners from the 16th PLMA awards, Viking Cold Solutions, about using thermal energy storage as a great asset. We're joined by Collin Coker of Viking Cold Solutions.

I think Thermal Energy Storage is a bit of a new technology to many of our listeners, myself included. Could you just talk a little bit about some of the primary applications of Viking Cold thermal energy storage systems and how your technology is maybe different from what we're used to?

Coker: We specialize in a technology we call the Thermal Energy Storage System, which is comprised of two key components. It uses phase-change material housed inside what we refer to as cells that are installed inside cold storage facilities, paired with the intelligence of the building automation controller and software written to sequence and identify optimization strategies within these facilities. The primary vertical is cold storage low-temperature freezers in particular is where the company's been focused across large commercial and industrial facilities for the past eight years since inception and early development of the technology.

In recent years we've begun to be much more commercialized and have expanded that focus all the way down to quick serve restaurants and grocery store applications for small walk-in freezers. But the primary fairway here is commercial and industrial applications with these cold storage facilities which are very prolific within large metropolitan areas, cities, towns, anywhere that you have populations that eat food, there's always a certain amount of frozen food and that's the area that tends to be the biggest energy hog with the utility and the highest energy cost for the customer. That's where we focus our efforts.

The facility sizes range from small to large, the uniqueness of the technology is that it is actually an energy storage medium with an efficiency play. This is not a parasitic technology that is only able to concentrate on shifting load from one part of the day to the other. If you understand refrigeration, which most of your listeners have a keen sense of understanding and experience depending on when you use your refrigeration can make a big difference on how efficient it is. And this technology enables that refrigeration system to run more in the evening, late night and early morning hours using less energy and then idle



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refrigeration and ride on the TES for long periods of time when the ambient temperatures are very warm.

There are no mechanical components to the system, the cells are mounted up in the very top of the racking system, and you can see many examples of installation pictures on our website. We use the natural laws of convection. As heat enters these rooms it rises and is absorbed much more effectively by our cells than the frozen food, which normally absorbs the heat.

We don't require any additional real estate. This technology is designed to fit within the existing racking systems, or on the ceiling infrastructure in some cases. Which are areas that are already being cooled by the existing system, and it doesn't take any additional real estate or pallet space away from customers. The system is designed to have a life of more than 20 years. As a thermal battery it has a hundred percent round trip efficiency; we're using the air flow from the existing mechanical equipment and energy transfers across that air, compared to lithium ion batteries where you have efficiency losses. Systems are very environmentally friendly and a hundred percent recyclable. All the formulas in the cells are water based with different types of salts that are ingredients commonly found in food.

When it comes down to the economics, compared to a lithium ion type of battery storage, this thermal battery has a levelized cost of energy less than 2 cents per kilowatt hour, versus lithium ion energy storage which has a levelized cost of energy of roughly 19 cents per kilowatt hour. So significantly more economically viable and more environmentally friendly with a much larger impact, not only for the customers but the utility providers who are trying to manage their demand and the energy requirements.

Smith: It sounds like there really is a large range of potential facilities that could utilize the technology. Could you just share with us the average maybe system size and your thoughts on the opportunity for this type of storage and market penetration.

Coker: Very large opportunity, obviously worldwide, frozen food storage has a worldwide opportunity for greater efficiency. This technology is designed to go into walk in freezers all the way up to industrial sites, and I'll use standard of measure, which is in square feet. You're talking about hundreds of thousands of square feet in some of the larger facilities. So, picture a football field, and put about three to four of them together, and put a roof on it maybe 40 to 50 feet high, and that's a very large facility that's packed full of frozen food.

There are several thousand of these facilities on the industrial side just across the US alone. When you add in restaurants and grocery stores and quick serve restaurants, you're talking about hundreds of thousands of locations on the smaller side that can be aggregated to make a bigger difference. And the overall storage capacity is multiple gigawatts of capacity across the sector. So, lots of opportunity, lots of scale and big impact in a big way.

Smith: When did Viking Cold start deploying systems? And could you share some of the results you've seen from actual installs?

Coker: The owner, founder and inventor of the patented system, started out of Jacksonville, Florida. He's been in the food shipping business for many, many years since the early nineties and started the business with the idea of retrofitting a couple of shipping containers with PCM tubes that were used at the time. He did several thousand trips for Walmart using phase-change material. One interesting data point, he did an 84 hour trip from Jacksonville to Puerto Rico on a non-refrigerated container with frozen food, and only had roughly a four degree temperature rise over that 84-hour journey. So, it was quite astounding that the phase-change material was able to absorb all the heat infiltration for that long period of time. That's the genesis of the company.

Then early installations began to proliferate into buildings, where we added controls and intelligence to the equation and were able to make much larger impact. So, we've had an interesting timeline of growth, I'd say our earliest installations have been performing for over eight years steadily. Some of our early customers have installed multiple systems. Across the 50 systems that have been installed so far, the average performance on energy savings overall, and that's kilowatt hours, has been 26% on the average.

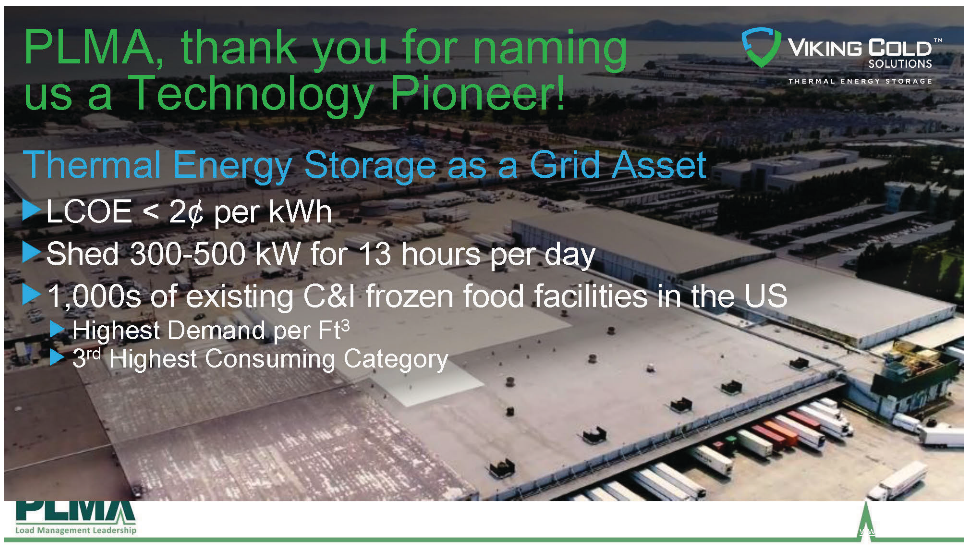
And again, it depends on the facility, and it depends on the size, the scale, the efficiency of the building construction, so it can range anywhere from a minimum of 10% all the way up to as high as 40%+ .

Smith: There are certainly energy benefits to the technology. Could you share any other maybe non-energy benefits that your technology can provide the customers?

Coker: I mentioned a little bit earlier about the efficiency piece. This technology is easy to understand, most folks pick up very quickly that they get the load shed element. Okay, so you've got this thermal cell, this thermal battery, if you will, that is able to augment cooling and provide protection for that food during long periods of vital refrigeration. They get that load shift piece. How does the efficiency really play in? That again goes back to refrigeration and being able to run more compression or more compressor run time in the evening in lower temperature conditions.

The demand is quite astounding, we've seen results in some of our larger facilities in Northern California for example, we've got one where we're helping the customer shed close to half a megawatt for over 13 hours a day for six days a week. So that's across both the part peak and the peak period of day, in the PG&E territory. This is a 93,000-square foot facility and has performed steadily ever since the installation and illustrates the magnitude of the impact. So, that's not only in that particular instance, not only an overall average 21% reduction of kilowatt hours, but overall, it's close to a 43% cost reduction during that 13-hour period of customer's operations. So, a significant impact.

Other than the efficiency and the demand savings, you get the flexibility based on varying demand patterns. We installed one facility in Southern California as part of an Emerging Technology Coordinating Council initiative through San Diego Gas and Electric, about three years ago. One of the facilities that was chosen was the San Diego Food Bank, which already had an existing photovoltaic system on their roof. They had a bit of



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excess generation that they were selling back to the grid at quite a bit of a discount. They had this duck curve challenge from a utility perspective with a lot of that load coming back on the grid for a short period of time when the sun goes down. The request was to have the technology affect that 4-hour period from roughly 5:00 to 9:00 in the evening.

The result on that facility, and it's still operating today, is that technology has helped take that facility off the grid completely at night. Dropping from roughly 40 KW from 7:00 PM in the evening until 7:00 AM the next morning, and they do that every day. So, it's been quite a phenomenal result. Really opened the eyes of a lot of folks, including ourselves, as we've gone through this learning journey of how well our technology pairs with solar, or any type of renewable energy. We can actually use that energy that's generated during the day from a renewable resource to run the refrigeration during the day, which is the opposite our normal operating paradigm, to freeze the cells and put them in a charged state. Then we discharge during the evening hours. This helps the economics and the financial payback on solar installations and helps the grid manage those spiky loads that tend to take the shape of the infamous duck curve.

You've got efficiency, you've got flexibility in the different demand patterns that we can work with, the temperature stability is a key aspect to these owners, operators, and manufacturers of food. The more that food changes temperature on the journey from the time it's harvested on the farm to the consumer's fork the lower the quality. It's an amazing journey, you get to really spend some time in this industry seeing it. How it's manufactured, it's initially blast-frozen, it's put into storage, it's moved through several different transportation means until it arrives in the local distribution loop, and then to the grocer and then ultimately to the consumer. But every time the food changes temperature, if it increases or cools down, an effect called micro thawing and freezing occurs, which has an effect on the food, the taste, the texture, and in the end the shelf life.

Having temperature stability, being able to ride with idle refrigeration for long periods of time without affecting the food has really never been able to be done before. Owners and operators in some cases do use the food as a battery, but it has very limited capacity, so the food goes through this micro thawing and freezing effect. Not to get too much in the weeds on that one, but the food protection is a key benefit to our system.

We also have increased visibility. The system offers granular level visibility all the way down to the evaporators, the compressors, refrigeration pumps, all of those items that run that low temperature freezer. We now have access through a portal that's providing information to the customer or utilities in real time to see how we're operating across measures of temperatures, air temperature, a food simulated temperature, and a cell temperature as well as energy monitoring. The systems manages for demand shedding and shifting and for efficiency, but not least of all is the resiliency.

A facility that has thermal cells or this energy storage installed versus one with just the food alone has roughly three times more thermal capacity and the ability to go for three times longer if there's a mechanical failure or if there's a power outage that would affect that facility. So they've got a great resiliency play along with the other efficiency, demand flexibility, temperature stability, visibility and food protection.

Smith: You mentioned one of your deployments, San Diego Food Bank, I know we've heard a little bit at PLMA about your projects with Eversource, would you mind sharing through some other partners you've worked with or other utilities or other locations and maybe share a little bit my own personal interest about your experience with this technology, navigating the utility landscape?

Coker: Yeah, well there's no doubt utilities have been instrumental in a number of our deployments like the food bank. There are not a whole lot of people, until recently, who have known much about Viking Cold and what we do or that really understand the cold storage vertical. These facilities tend to be back off the main highways and the big buildings don't have a lot of detail on them. So, having the utilities understand that load, understand that having flexibility to shut these big energy hogs down when they need to, and not put their customer's food or product at risk has been a very good recipe.

I'd like to speak a little bit about Eversource, the team there has been wonderful to work with, we're part of a demand management study in a program right now where Viking Cold technology along with several other technologies including other energy storage, battery storage, control, and demand response companies were given the opportunity to take some of money that was put aside to support technology implementation and target a four hour ICAP period in the Eversource market. We have completed eight installations in that market, ranging from small regional food processors all the way up to large 3PL companies, and food distribution companies that you may be very familiar with. We've been able to help them take roughly 1.2 megawatts off of the grid during that targeted 4-hour period of time.

Just to give the audience an idea of how quickly we were able to implement the technology, and how effective it has been, the time frame was about 6 months. We received the first signed applications from the customers in January and by early June we were able to complete the installations, get the customers up and running and provide demand management through a measurement period at the end of September. We hope to continue to work with Eversource to have a program to support the technology moving forward.

The folks out in California have been instrumental, I can't thank the San Diego folks enough for allowing us to participate in that emerging technology program which provided a third-party engineering validation study. Some of the costing information in there is quite old, we've been able to reduce our costs quite a bit, so those of you who are interested in reading the study, we'll provide the link at the end of the program, but don't be alarmed at the cost at that time, we've been able to reduce our costs and be much more cost effective. With assistance from the utility programs, we're getting quite a bit in adoption from the customers.

We are an approved SGIP developer in California now across all the IOUs, that is a self-generation incentive program targeted at energy shift, our first installation has now been in place for over a year, and we're completing installations on a regular basis now to take advantage of the funding that's available. But this also helps the utilities accomplish their mission in deploying more energy storage, and it's been very effective so far.

Part of our strategy in the deployment of these systems are the food banks. The food banks have been introduced to us through the utilities, but it's a pay it forward strategy. A lot of what we found in early days is customers have a hard time understanding really what we do, and these owner/operators like to go touch it, see it, feel it and talk to the operators. So, will it help fund an installation along with the utility of a food bank, that can make a big difference in the local community and provide great visibility for future customers to see what their installation may look like in the future. So that's been a big part of working with utilities there as well.

We've been recently awarded projects in Southern California and we hope to expand into the Canadian market with our first installation announcement here in a short few months in the Ontario market. But we can't say enough for the other utilities that we're working with right now in select markets, mostly in the Northeast with not only demand management strategies in programs, but also energy efficiency that would be a deemed program. So, we're making a lot of progress very quickly, but definitely it's a win-win for both sides of the fence.

Smith: What we've heard about the benefits as far as efficiency, load management, temperature stability and improved food quality. Going forward, do you see other avenues, other benefits that this type of technology can provide?

Coker: I think this technology can be a big part of future microgrids and their technology implementation. We can be just one key component to a larger strategy, and that's where we found that we really created a lot of value. Not to mention the resiliency piece, so, the recent events in California are very unique with the wildfires, but the grids being shut down in high risk areas, and these commercial folks, ranging from grocery stores to cold storage facilities to convenience stores and restaurants. What do they do for an extended period? It could be as long as two days, this is a very low bar, low lift, easy implementation strategy that can help unique anomalies that occur such as that, with regards to resiliency factor. But definitely we're just one piece of the overall broader demand aggregation strategy to abate. Let's not build more generation, let's better utilize the renewable energy resources we have and have seen that are proven and be able to leverage all of that investment in the right way. Part of our mantra here is not the how, but it's the why. Why are we in business? And why did we design this technology, this method, and what helps to achieve the broader goals of renewable energy implementation and carbon footprint reduction?

Smith: Can the Viking technology be as effective for refrigerated storage as it is for frozen storage? And if that's not something on your plans now is that maybe in a future plan?

Coker: We're not there right now, we do think that at some point in the future we'll come up with the right application and the right installation methods. But right now, we are solely focused only in the low-temperature freezing space. And all of the formulas we have at this point are all water-based, and that's one of the key things is when you get above freezing, you have to use different types of phase change materials that are either organic, oil, paraffin-based, not necessarily food safe. So, we've got some work to do, but we do see that we'll be able to penetrate that at some point in the future. Right now, all low-temp focus.

Smith: What are a couple of things that if listeners take away nothing else they should take away from this, regarding thermal energy storage, and then if folks are interested in learning more, what's the best way for them to do so?

Coker: The best way to learn more is definitely reach out to us, we've got what I feel is a very good website, the resources tab on the website is very complete with white papers, videos, and case studies. We've got a news page for recent articles and press releases, we are gaining a lot of momentum, today's podcast is one example where we've been blessed with having folks like you that allow us to tell the story. Where do we go from here? I have just a few takeaways. Consumers can now think entirely different about their procurement strategy. This is a thermal battery, this is an enabler, this allows them to no longer be a price taker deregulated markets, for example. They could actually have the flexibility to go to a market settlement base type in lieu of paying a premium for a fixed price.

Programs that we're seeing from utilities are more focused on daily management, not just peak management. Eversource and I think National Grid both introduced daily dispatch programs that put more emphasis on daily management. Customers should take advantage of fairly rich incentives for these implementation opportunities. But both from a consumer and a utility side, you can think entirely different about this load, how it's managed and how it can benefit both load reduction and efficiency goals. We have the capacity to do that, it's a proven technology and it can make a big difference in a very quick period of time.

www.etcc-ca.com/reports/phase-change-material-and-controls-study-low-temp-refrigeration-applications

The conversation above is from a webcast recording at https://bit.ly/2U77aGB