Practitioner Perspectives™

Thought Leadership 2018

A Compendium of Industry Viewpoints

Produced by
PLMA Thought Leadership Group
January 2019

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Chaired by Rich Philip, Duke Energy

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The Group seeks to enhance PLMA's role as a facilitator of industry thought leadership and will continue to position PLMA as the leading community of load management practitioners dedicated to sharing knowledge and best practices.

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THOUGHT LEADERSHIP

Richard Philip, Duke Energy

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As presented at 37th PLMA Conference in Coronado, California on April 17, 2018

Moderator Mark Martinez, Southern California Edison

Kent Walter, Arizona Public Service

Fabienne Arnoud, Pacific Gas & Electric

Brad Mantz, San Diego Gas & Electric

Richard Barone, Hawaiian Electric

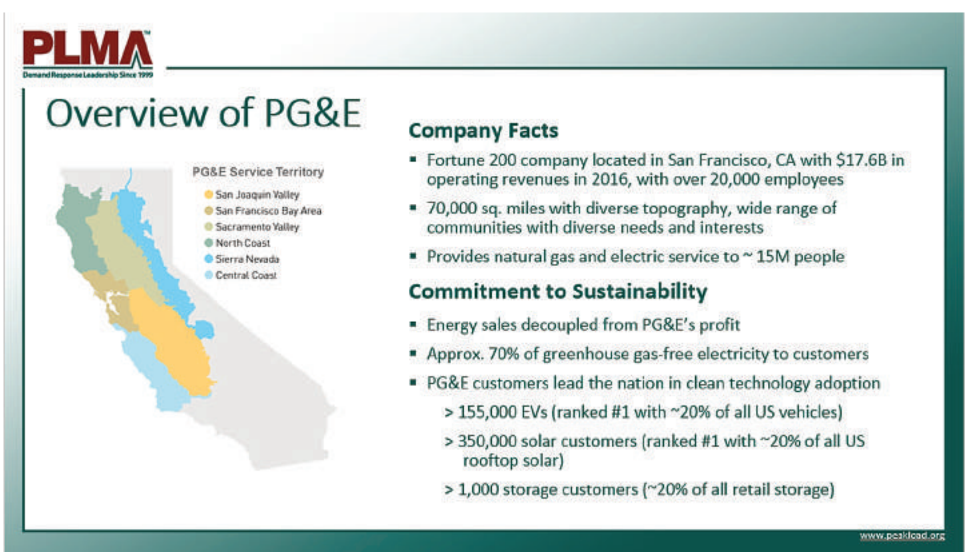
Darren Hanway, SoCal Gas

Discover how utilities in California and other Western States, as well as Hawaii, are repurposing traditional demand response initiatives to meet an emerging technological future through dynamic retail pricing, distributed energy resources, and beneficial load growth goals for peak load management, renewable integration, grid resiliency, and much more.

Mark Martinez: Today we're going to look at how utilities in California and other western states, as well as Hawaii, are repurposing traditional demand response initiatives. They're basically trying to meet an emerging technological future through dynamic retail pricing, distributed energy resources, and beneficial load growth for peak load management, renewable integration, grid resiliency, and much more.

I think Andrea (our morning session co-chair) previously talked about the work that emerging technologies are doing. And having been with this organization for a few years, we've talked about demand response and how it's traditionally worked with air conditioners, thermostats, pumps. We now have a new set of technologies that may not be necessarily demand responsive but are affecting how the grid operates. Electric vehicles, solar panels, batteries now. I think it's going to be important to see how we address all these things. And there's a new component of demand response, which involves natural gas. I would like to introduce our first speaker, Fabienne Arnoud. She is the manager of demand response policy and pilots at Pacific Gas & Electric in the Grid Innovation Department, which is responsible for testing solutions to transition to the grid of the future. She leads the team that develops the future road map for demand response using pilots and emerging technology assessments while making sure that decisions are informed by the regulatory policy drivers. Fabienne joined PG&E in 2012 and has held several roles in policy and strategy. She holds a master's engineering degree from Telecom INT France, and has worked in information and communication technologies before transitioning to energy.

Fabienne Arnoud: Thanks, Mark, and good morning, everyone. Let me start with a few words about PG&E. It's one of the largest utilities in the US. We have about 24,000 employees, 70,000 square miles of service territory in Northern and Central California where we deliver natural gas and electric services to about 15 million customers. PG&E has a strong commitment to sustainability and environmental leadership. It's been supporting public policies that promote energy efficiency, clean energy, and most importantly, our customers are a major driver behind this commitment as we see them lead the nation with their adoption of clean technologies. I've put up



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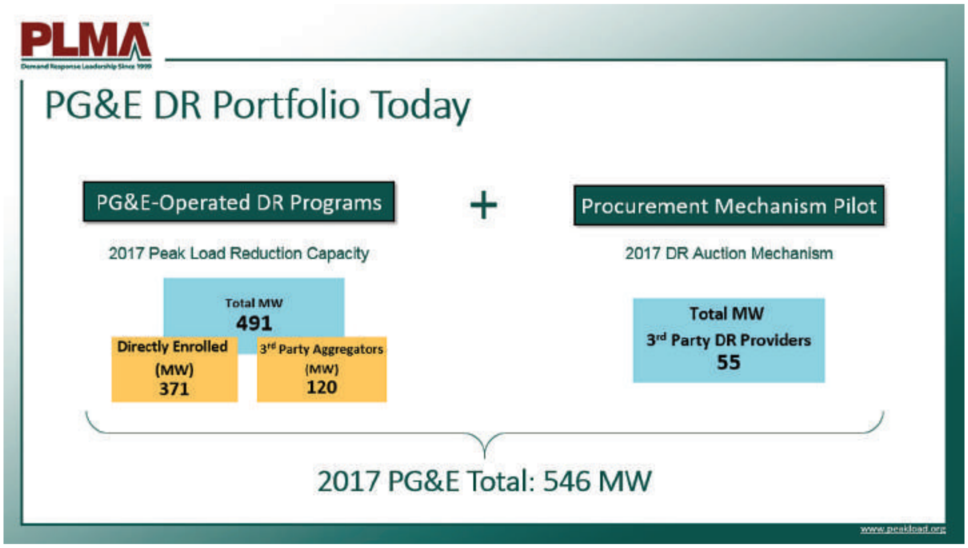

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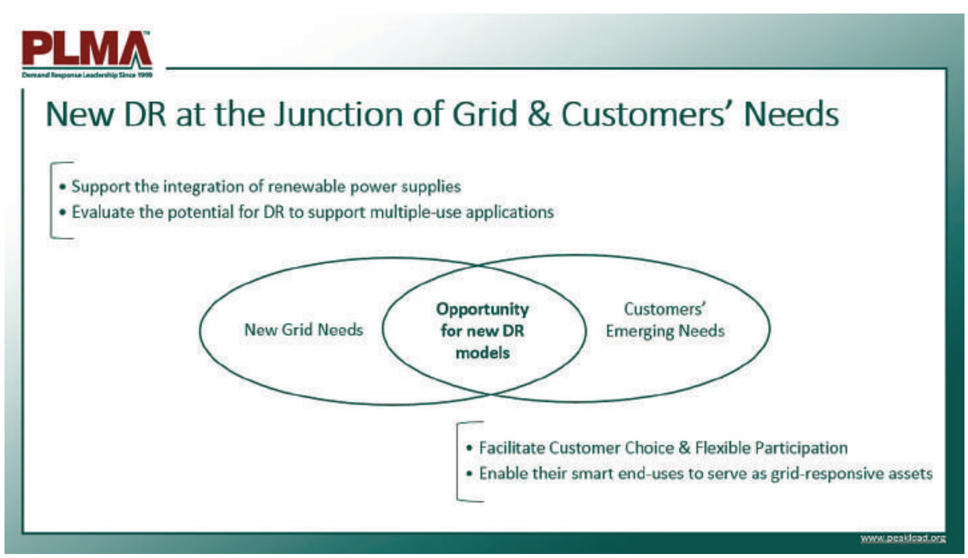
there some numbers in terms of adoptions for electric vehicles and retail batteries. [Slide 2]

And I think it's relevant to our conversation today because those are smart connected end-uses that can receive dispatch signals and essentially act as DR by providing services to the grid. That context is important for today's conversation on the future potential growth of DR.

Before we talk about how DR is changing, this is a snapshot of where we stand today with PG&E's 2017 portfolio of peak shaving DR. [Slide 3] What you see on the left is 491 megawatts that essentially come from PG&E-operated DR programs. We've got some directly enrolled customers mostly in our critical peak pricing rates. But a big part of what we do is really working with aggregators as they account for about a fourth of the capacity that we have there. And we add to this the 55 megawatts that you have on the right, and that comes from the DR Auction Mechanism or DRAM, which is a procurement pilot that we've been doing in California these past few years. The idea is that PG&E buys resource adequacy tags from third-party DR providers. And then these parties directly bid into the California ISO energy markets to fulfill their resource adequacy requirements. So, that brings us to a total of 546 megawatts. And then, one final slide maybe as a backdrop for upcoming questions to illustrate that when we think about the future roadmap for DR, we're really looking for opportunities at the intersection of emerging customers and grid needs. [Slide 4]

On the grid side, I'm gonna mention a couple. We think that DR may be able to help even more with the integration of renewables on the grid, beyond load shed, developing a new reverse DR model that we would dispatch for load consumption in situations of overgeneration in the middle of the day. If DR can be dispatched by the CAISO, then the next frontier could be to figure if DR could also help with distribution services like distribution deferral. And that's something that will quickly get us into the multiple-use applications territory, where we're gonna need to figure how a DR resource can provide multiple reliability services potentially to multiple masters. And we're gonna have to figure how that DR resource can provide this in a way that doesn't compromise the delivery of any of those services, keeping an eye, of course, on the safe and reliable operations of the distribution grid.

Finally, on the customer side of that equation, I think that the big question for us is: Can customers show up? Will they be able to show up in a way that helps the grid but also is worth their opportunity cost? And here, I think a big part of the answer is the fact that people are adopting



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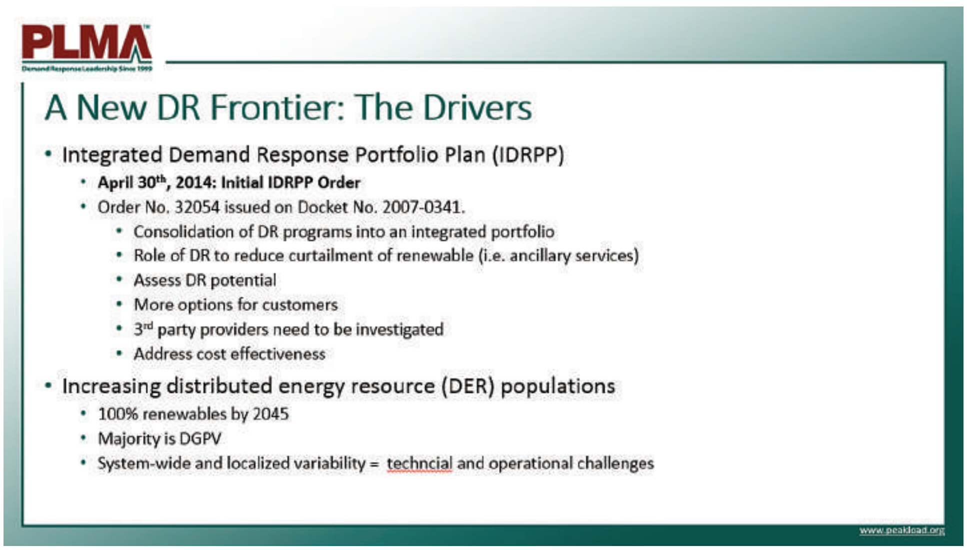
smart devices for their home, for their businesses, back to what I was mentioning on the first slide.

I really think that this creates an opportunity for DR to become the platform–by that, I mean the processes, the IT systems, the rules, the programs–to help transform those smart devices into grid-responsive assets. And I think the value there for customers is that they would earn additional revenue from DR on top of optimizing their bill and really make the most of their investments in smart devices that way. Hopefully, that gives us some good background for upcoming questions.

Martinez: I'd like to introduce our next speaker, a gentleman by the name of Rich Barone. Rich is the manager of the demand response department at Hawaiian Electric and the co-chair of the PLMA DER Integration Interest Group. He provides leadership and direction of the DR strategy business cases, technologies, program portfolio, and market development. Rich joined Hawaiian Electric with over 15 years of strategic planning and early stage technology assessment. His most recent experience was as the associated director in Emerging Technologies, again, at Navigant Consulting. He was previously employed also at Pacific Controls as the VP of Smart Grid Services. Rich holds an MS in engineering technology and policy, and an MBA in entrepreneurship from University of Colorado. He earned his MS in e-commerce application development from Columbia University. And he holds a dual BA in English and Philosophy from Boston College. So Rich, let's hear a little bit about Hawaiian Electric.



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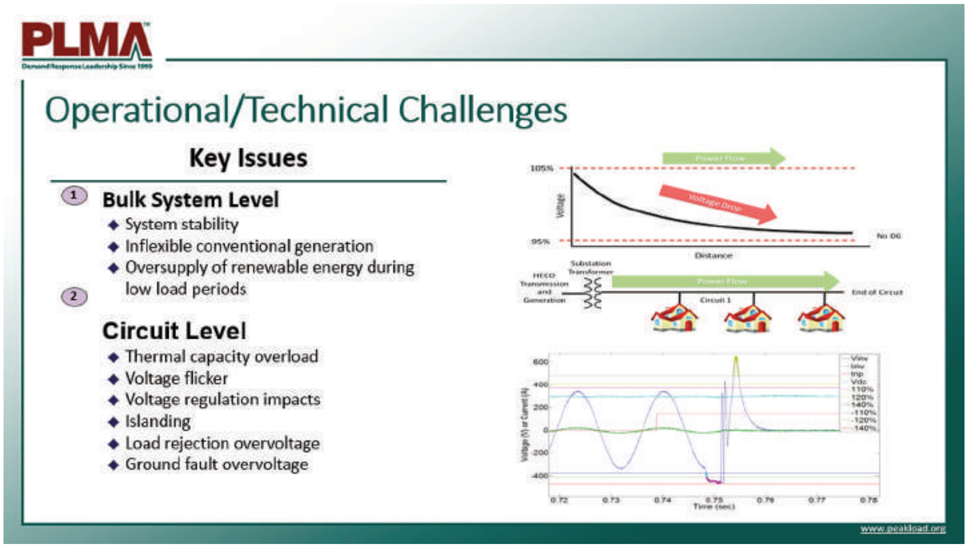
Rich Barone: By comparison, Hawaiian Electric systems are small, but by no means, simple. The parent company, Hawaiian Electric Companies, is Hawaiian Electric, which is Oahu, Maui Electric Company which is Maui, obviously, and Lanai and Molokai. And then Hawaii Electric Light which is the big island or Hawaii Island. And as you can see, our system is relatively aggressively pursuing 100% RPS (renewable portfolio standard) by 2045. And the dispersement across the different systems varies quite a bit. Oahu is our biggest system with about 1,200 megawatts-ish peak capacity, peak load, and of that we're right at the 20% mark. Some of the other islands, like big island, is a lot higher. This is just a little bit of a snapshot of our system. The only sort of major island in Hawaii that we are not responsible for delivering electricity on is Kauai. As we look into the future here, I just thought it would be important to highlight why are we here?

What has pushed DR into the future in Hawaii? [Slide 6] There's a couple of things at play here. Firstly in 2014 in a sweeping, batch of regulation from our public utilities commission, one of the four major tenets that they threw out there was a DR policy statement. And this was all woven into an inclinations paper that they put out which really expressed a desire for the future of our overall energy paradigm. The DR policy statement called out the need to do an integrated portfolio of demand response, one that did address the reliability needs of the system and could support the avoidance of curtailment of renewables. The flip side of that is to support the integration of renewables especially in the face of increasing threats to system resilience and reliability, somewhat caused by some of those renewables. They also encouraged us, or more than encouraged us–ordered us–to investigate third party and market-based solutions. We had to go beyond strictly administrating programs as the utility, and look at the cost effectiveness and potentials woven into this order.

If you look at that in tandem with 100% RPS and the fact that majority of those systems now and potentially even into the future, our DGPV (distributed-generation photovoltaic), demand response becomes a likely candidate for helping to directly solve those problems



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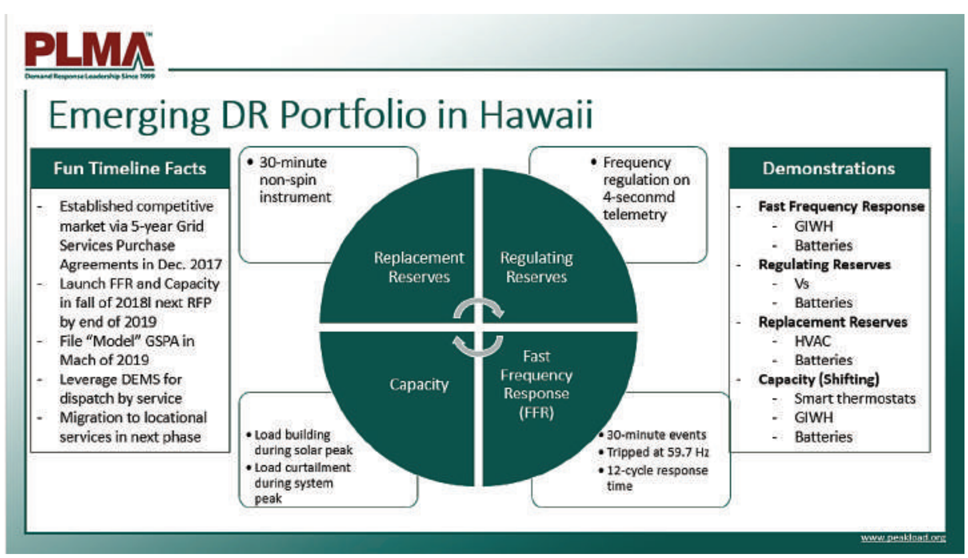
controlled programs. As you can see from the picture here, last year we finally filed a final application to promote something novel we had to take on the challenges of not having an ISO and create these sorts of bulk system services. [Slide 8]

We created grid service tariffs and those tariffs are actually definition of the rules of the grid services that we need. From there, we then delivered a bunch of rates and riders that are really the programs to support those. But to some extent because the commission wanted us to take a market facing approach, that really became a straw man. What we turned that into is using those grid services rules as the basis, we introduced the multiyear contract for the provision of grid services through third-party aggregators, the grid service purchase agreement. We have our first version. We expect to be contracting this summer for two services.

in the technical and operational challenges that arise. This just gives a little bit of a snapshot. Unlike other jurisdictions, we've got the full suite. We are to some extent an ISO, as well as a distribution company. [Slide 7] We've got your system–bulk system–challenges, and those are generally speaking a system instability, frequency in particular, caused by increasing amounts of variability on the system from renewable energy production. And then of course in addition to some of those dynamic instabilities, you've got a lot of production at certain hours of the day where you have the lowest loads. This general system load balancing is kind of the big picture challenge. And some of the variability that renewables are creating for our system results in something like the need for regulation service but maybe something slightly slower than that.

We're looking at services that we really haven't even defined yet, and have a need for. But then you want to look further downstream at the circuit level, and this is really challenging. You can see a number of the issues at the circuit level are voltage specific, but you do have thermal capacity constraints at the circuits, especially caused by PV, and battery systems that do result in energy export. So, what we have done about this, and what we're doing about it. Now we've had legacy programs historically for over a decade in Hawaii; predominantly those are load

One is a capacity service where there's two sub services. There's a load building service in the middle of the day and a curtailment service in the evening hours. We've also got a fast frequency response service. We don't have the luxury of a big safety net in terms of system inertia and so increasingly we're seeing more exposure to frequency decay. Cutting off a load or injecting power into a system from customer assets can arrest the frequency decay so it's a big need for us. A little bit longer term, we expect to



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get a model grid service purchase agreement filed next March, after a year's worth of stakeholder engagement.

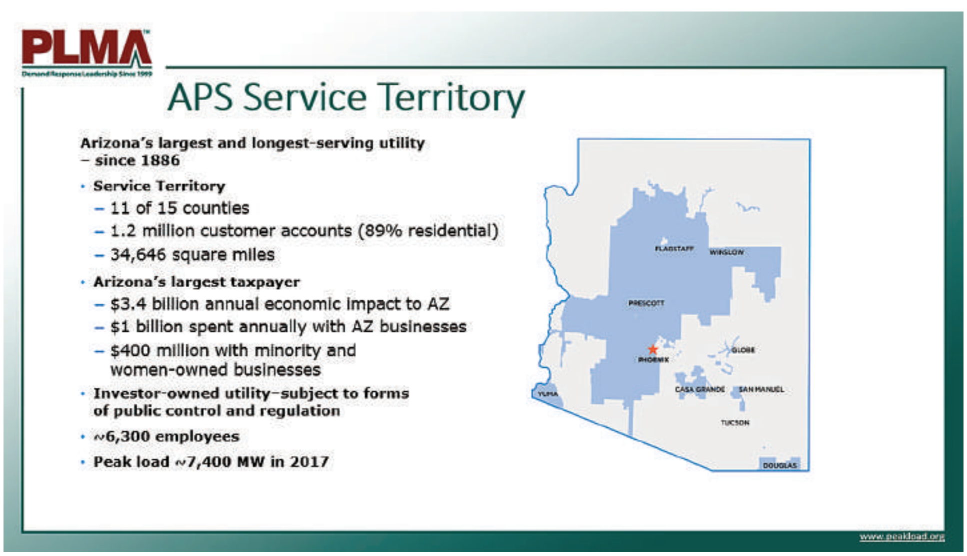
To have a contract in hand that we can continue to execute without continuous commission approval. So that's a big deal for us in the months ahead. A quick note about some of the demonstration work we've already done. We've already, over the last year we worked with five different vendors for various technologies including electric vehicles, batteries, hot water heaters, HVAC systems, smart thermostats to demonstrate each of the four services that we're talking about to make sure there is market validity and technical efficacy to deliver these. So that's where we are and that's the future we're heading into. Thanks for letting me share that with you.

Martinez: We left San Francisco, took a little side trip to Hawaii. But before we come back to California, let's fly over to Arizona, into Phoenix, and let's visit Arizona Public Service. Kent Walker is the manager of Customer Technology Product Development. And his role at APS is to enable APS customers to achieve their energy related goals and mutual customer and grid value partnerships. In his more than ten years of energy experience, Ken has been the regulatory contact for the wholesale power trading operation, the leader of energy accounting, and he has helped to integrate APS into the regional energy and balanced market. So, say hello to Arizona, and welcome Kent Walker.

Kent Walter: I can't sit still long enough to present, so this is a good break for me to get up and move around. Kent Walter, manager of APS's Customer Technology Product Development. I appreciate you guys having me here today. A few notable characteristics of APS, we're in the desert, we have incredibly hot summers, temperatures do reach up to 120 degrees and that drives an incredible demand on our system north of 7 gigawatts. [Slide 9] And then when it's not those four months of summer, it's incredibly beautiful. And so, we have less than four gigawatts of demand on our system. As a result, there are some incredible seasonal variations around our resource needs. A lot of needs in the summer, very little needs in non-summer. Another notable characteristic is APS has around 60% of its customers on modern rate structures.

Modern rates are TOU or TOU plus demand rates. We talk about them like they're new things but APS has had residential demand rates since the 1980s and residential TOU rates since the 1990s. So, our customers are very accustomed to understanding when energy has value and when it doesn't. One of the things I want to talk about today was our revolving resource needs and I thought these two graphs really illustrate what our challenges are. On the graph on the left here illustrates our summer. [Slide 10] As you can see, we talked about this a lot in terms of managing peak and what our needs are for looking. And for our service territory, for our customers that continues to be a need. Our peak load continues to climb and it continues to grow even later into the day, forward looking. But what we haven't talked a lot about is managing this non-summer timeframe. This duck curve timeframe. A lot of you have heard that word, I've just glossed over it a little bit but I'll offer just a little bit of discussion around it. So, what that really is, is it's a time frame when customers are using less energy from the grid.

One in 17 of our customers have rooftop solar today and it's anticipated that will grow. And so, when they use less energy from the grid it doesn't mean we can shut down resources. Much like your car going down a hill, you take your foot of the gas but your car doesn't shut off, it goes to a minimum RPM or idling condition to maintain engine stability because you're gonna jam on the gas to go up the hill on the other side. Similarly, the generating resources do the same and there ends up being a supply of energy that is in excess of what there's demand on the system, which results in negative pricing. I've been following the prices since I've been here and every day,



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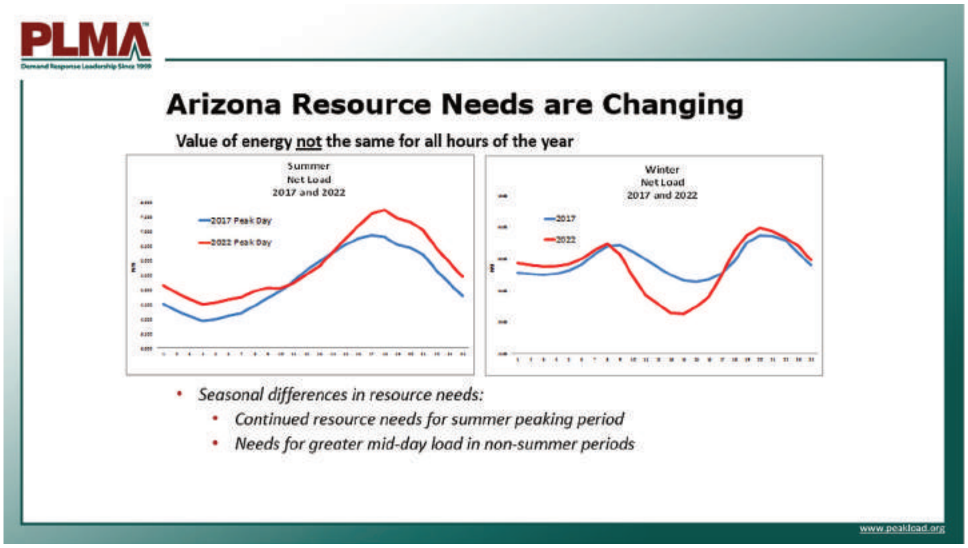

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without fail, checking around that 10 o'clock, 11 o'clock we definitely have nodes that are negatively priced. We have more energy than there's demand on the system. And so, we've sought an approach through modern rates to help be able to address some of that.

But we're looking at technology differently. And we're looking at technology in a way that's more granular, to see how it not just solves the summer peak need, but now how do we solve our year-round challenges? We are very bullish on things like water heaters, which are inexpensive battery opportunities for customers, with very little impact to customers. But it also makes us look at other technologies like thermostats differently as well. And we deploy thermostats and we assume we're going to get a peak savings. But the actual function of a thermostat increases the temperature at 8 o'clock, builds up a thermal demand while the residential customer's at work. And then turns down the system and exercises that thermal demand at 4 o'clock to 8 o'clock, right when the system has peaks. So, needing to challenge and address technology differences.

Now, that's the summer. In non-summer, it truly is avoiding clean energy that's otherwise curtailed and coming down into that large ramping period, exacerbating that ramp. And so, we're engaging in conversations with our customers to better inform them how their actions impact sustainability. How their choices with technology can help them better utilize what is otherwise underutilized resources. Or build value for timeframes that have quite a bit of clean energy resources.

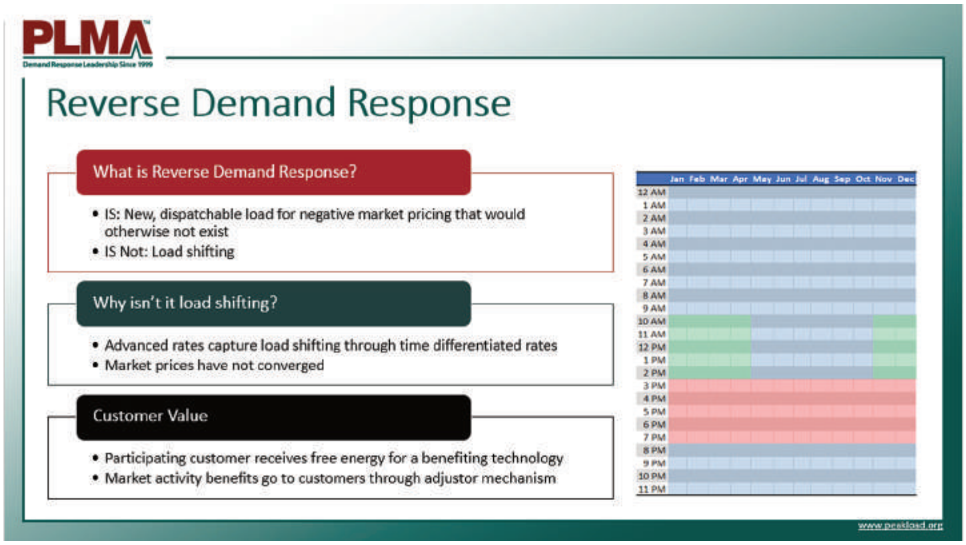
EVs is another great example. Under our new rates, we have a super off-peak period. That's a residential rate from 10 AM to 3 PM from November to April. It's a five-hour block, six months of the year, which residential energy rates are 3 cents a kilowatt hour. That's equivalent to charging an EV at less than 30 cents a gallon of gasoline. It's a terrific opportunity for a customer to do something that is adopting a resource in a very clean manner. And by the way, in 2017, that same timeframe, wholesale energy prices were negatively priced in Arizona 27% of the time.

There's an abundant supply of energy, just figuring out how do we approach customers and engage them to use it. Energy efficiency, challenging our energy efficiency portfolio to be less about driving compliance and more about driving value. APS stopped funding LEDs earlier this year, because LEDs have transformed in the marketplace.

They're here. We don't need to spend customer dollars to drive that adoption. The marketplace didn't change, in fact, I'm certain nobody here heard anything about it. We didn't either in Arizona because customers are already buying these efficient technologies. It's now about educating and directing customers in how they can achieve real value through modern rate structure or utility programs.

So, with that, we talked about the summer time need and we have a toolset to be able to address summer peak and we're executing to that toolset. But as we approach our customers, we're trying to engage them in ways that are addressing our new needs or year-round resources. So, we've introduced this last September to our commission, a concept called reverse demand response, which is free energy for customers that's dispatchable during negative pricing. [Slide 11] Now, it's important to understand what energy reverse demand response is and what it isn't. So reverse demand response is community benefiting; loads that would otherwise not exist. This is things like heated sidewalks to melt snow in Northern Arizona, fountains, or other opportunities for customers to get creative around what that might look like. And so, ways we can engage them to be able to use this.

What it is not is load shifting, right? It's not batteries, it's not EVs, it's not anything else of this nature. That would be a terrible use of those technologies, right? Negative pricing exists when you don't have enough demand to support energy. Batteries and other load shifting



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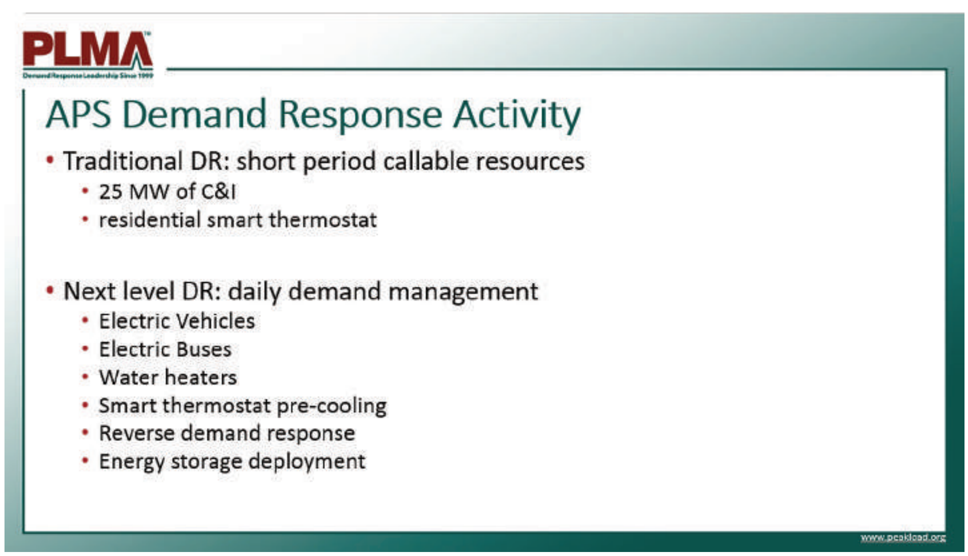
technologies are better used to prevent the negative pricing from happening in the first place by adding the demand to the system. But we are working on other opportunities to be able to engage those types of things in more dispatchable and dynamic ways. It just isn't the reversed demand response, and this gives customers an opportunity to be flexible with us. On the right side, you see our TOU structure, our on-peak periods are defined by three o'clock to eight o'clock period. And our super off peak is that ten o'clock to three o'clock window from November to April. Just good information to have. Last thing, we're trying to do this in a lot of different ways and trying to be able to approach this not as a single tool in the toolset but as a group of tools. No single tool we have is going to be enough to be able to manage this. I mentioned we're above seven gigawatts in terms of overall generation. Last year, just residential, we had 155 megawatts of rooftop solar interconnect. The year before, we had 135 megawatts. So, we'll continue to see this challenge well into the future.

And so, we're looking at other ways to get customers to be able to better use those clean energy resources. [Slide 12] So, we've introduced programs around electric vehicles, electric buses which I absolutely love, right? Buses go out, they run, they pick up kids, they take them to school, and then they sit idle. Absolutely perfect opportunity to charge in the middle of the day, particular during those non- summer months. And then after they run their afternoon routes, those buses don't need to be charged again until the morning, and so they can avoid the on-peak timeframe. This becomes a year-round resource opportunity. Buses that aren't in service during the summer, if they have a battery, have an opportunity then to also be able to do demand management and truly portable battery, right? Encouraging smarter use of thermostats. Pre-cooling in advance of that peak period. Your home is very low grade, but battery. And so using energy smarter results in both customer savings as well as value for the system. We're certainly in it together with our customers. Now, of other opportunities with battery storage and others, but I think I've exhausted my time. Thank you so much for having me and letting me speak to you today.

Martinez: So now let's take off from SkyHarbor Airport in Arizona and go to Los Angeles. But before we go and visit another electric utility, we're now going to make a stop at a gas utility. Now, Lisa, in her welcoming remarks this morning, mentioned that in a few years, we'd be interested in seeing what demand response looks like right now.



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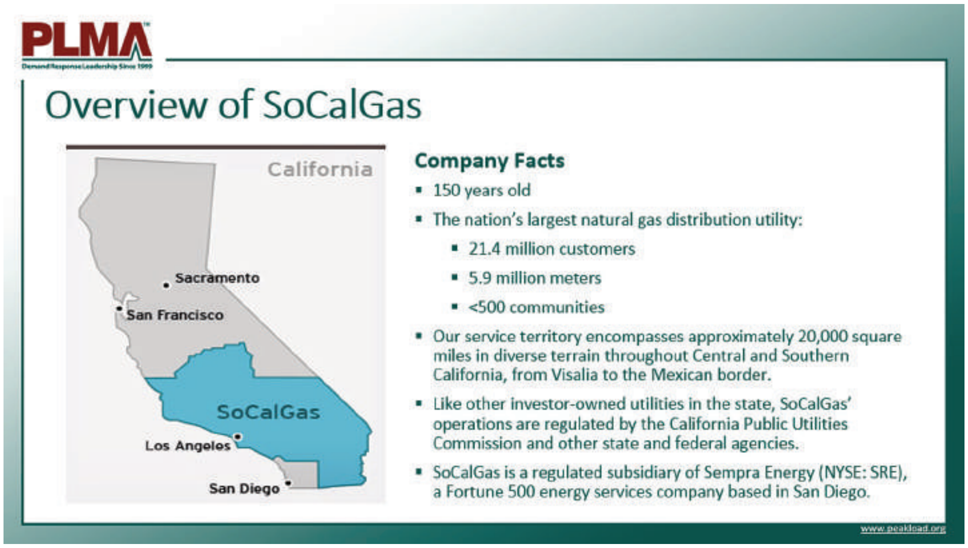

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Well, it's changing today. And it's changing in an interesting way as that we've now adopted a new fuel for demand response, natural gas. I'd like to introduce Darren Hanway, who's the manager of energy efficiency (EE) programs for Southern California Gas Company, the nation's largest natural gas distribution utility. Darren leads the development design and implementation of energy efficiency, demand response, and solar thermal solutions for over 21 million customers in southern California. Prior to his current role, Darren managed SoCalGas' energy efficiency policy and advocacy effort. And Darren holds a Bachelor of Science degree in Business Finance from the University of Southern California.

Darren Hanway: SoCalGas turned 150 years old this year, so we have a pretty tremendous legacy in the Los Angeles area. [Slide 13] We actually started by providing heating oil for the city's street lights 150 years ago. So over 21 million customers across about 6 million meters, the vast majority of those are residential meters. Very large service territory, we provide the gas all the way from the border with Mexico to our sister utility, SDG&E, all the way up to Central California where we start to bleed in to PG&E's area. But obviously, an outlier on this panel but I'm happy to be here.

About couple years ago, we have a variety of storage fields. One of those storage fields are largest, in fact, the second largest in the country. It had some operational issues that prevented it from being fully operational for the past couple of years. And so, we were looking at other opportunities to prevent reliability concerns on our system, and to continue to identify solutions to help our customers better manage and optimize their energy use. And so that's what my team does on the customer facing side. My team, we manage all of our energy efficiency programs, our solar thermal efforts. And now, our demand response program, so it's been an interesting journey for us. I don't have a slide with a lot of words because unlike my esteemed colleagues up on the stage, my team doesn't have a lot of experience in this particular area. [Slide 14]

But we are learning and we are identifying new solutions for our customers. So, if you look at our natural gas system, in the summer time, we have a peak. If it's really hot, then our electric generation customers, natural gas still fires about over 60% of all electricity in California, prevents the system from constraints in the middle of the day. And conversely, on the winter time, our peak is two-fold, driven by our heating customers. So, you see, between 5 and 9 AM in the morning and 5 and 9 PM in the evening when folks are either waking up and heating their homes, or they are getting back from work and also heating their homes.

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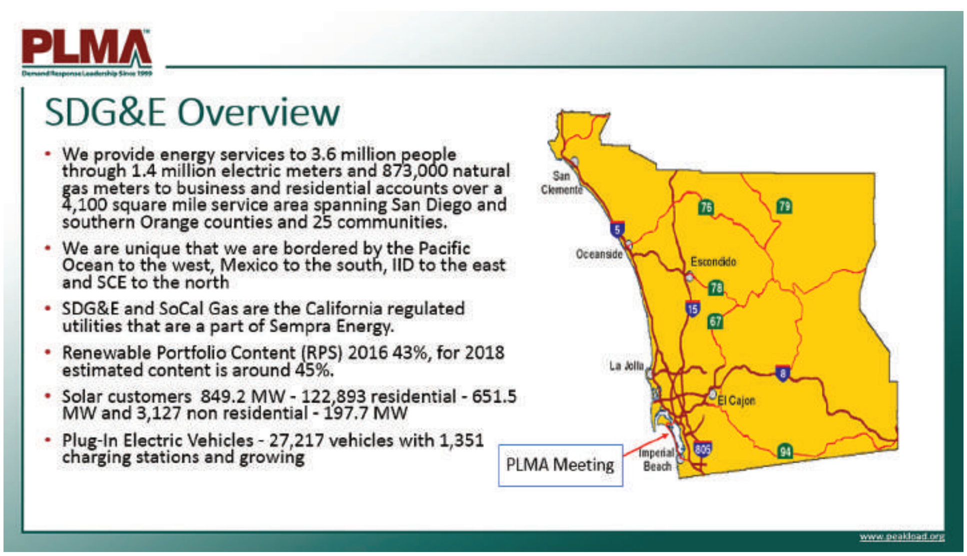
And so, we have attempted to identify a package of solutions to address those particular efforts. So most recently, this last winter season which we just concluded two weeks ago. We partnered with Nest, with EnergyHub, with ecobee, to do direct load control around focus on those two heating periods in the wintertime when our system needed those opportunities.

We had a very cold March and I'll say that it's cold by Los Angeles standards, in the 50s.

Sorry for everyone else who's not accustomed to our climate. But we did see about a ten-day period where we were calling events twice a day every single day to help mitigate some of our storage issues, and to bring system reliability to all of Southern California, not only on our gas side, but also from the electric side given the fact that we power most of the electricity. I have a picture of a water heater up here because this is one area where I think natural gas is clearly behind relative to our electric partners, and that is just the general connectivity of gas equipment versus electric equipment. Gas equipment is not as sexy as electric equipment, less WiFi, less connectivity, but we are seeing a move towards that. Obviously, the thermostat provides an entry point into the furnace. We are working with water heater manufacturers to provide WiFi connectivity around a traditional storage tank water heater that we could use as a dispatchable demand response resource. Again, nothing new from the electric side but it is a novel concept for us and we're very excited about it.



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We've seen connectivity now with ovens and even with ranges. And they have these cool retrofit knobs where you could pre-program cooking and it will turn up the temperature to cook a particular meal, turn it down when it needs to turn down all from your phone. So natural gas appliances are starting to become as connected as the electrical appliances and that provides an opportunity for us to engage with our residential customers around this kinda concept of demand response. So that's the future for us and we're excited to get there.

Martinez: Let's now come back home to San Diego. I'd like to introduce Brad Mantz, the Demand Response and Segmentation Manager for San Diego Gas and Electric. Brad is responsible for managing the demand response portfolio of all the programs for SDG&E. He has 25 years of experience in the energy sector. He has held many positions in electric and fuels procurement grading, origination in contract negotiation, risk management, mergers and acquisitions and project development of the US and around the world. And it's worth noting for interesting groups of folks here, British Petroleum, Williams, Sempra, Central & Southwest Corporation, Sumitomo, Nana Corporation and now San Diego Gas and Electric. Brad, you attended the University of California and the University of Texas in Austin. I think we're going to Austin next time. And that's where you earned degrees in marketing and petroleum land management and a minor in geology. So, let's welcome Brad.

Brad Mantz: I want to just thank you all for coming to beautiful San Diego and Coronado and I hope you are enjoying this great conference. We appreciate having you all here. San Diego Gas and Electric is a very unique utility. [Slide 15] We are owned by Sempra Energy as is our sister company SoCal Gas. And now the newest member of the Sempra team is Encore in Texas. So, it's going be really interesting the future of Sempra and its utilities. San Diego Gas and Electric is a pipes and wires company, most of our pipelines are controlled by SoCal Gas. They handle the procurement of the gas for our customers. And on our side, we procure the gas for our Power Plants and our generating partners. And that's really the only difference between us. We also generate and buy electricity. One interesting thing that I wanted to mention that I'd looked up yesterday is I don't think anybody in this room realized it, but for about three hours yesterday, we were running on almost 100% renewables. We had only one gas-fired plant running. And that was because, it was running at its minimum. So, we were basically 99.9% renewables.

I think that's a fascinating thing. And that's going to continue. That's the way of our future here. We're a very different type of utility in the sense that, one, we're kind of of almost like Hawaiian Electric in a slightly way, we're kind of an island. We have Mexico to the south, The Pacific Ocean, to the west. We have Imperial Irrigation District (IID) in the desert to the east and then we have LA and SoCal Edison up to the North. So most of our renewable energy either comes through Edison's territory from the north or comes through our Southwest Power Link or Sunrise Power Projects transmission lines coming out of IID or even farther out into Arizona. We're very dependent on those. If something goes down on those lines, we do run into problems. One thing we have really started to look at, and we've been a real leader in, is really getting rooftop solar on line, currently we have over 800 megawatts installed and growing and fortunately each and every one of those means we minimize the use of fossil fuel power plants. So that's exciting.

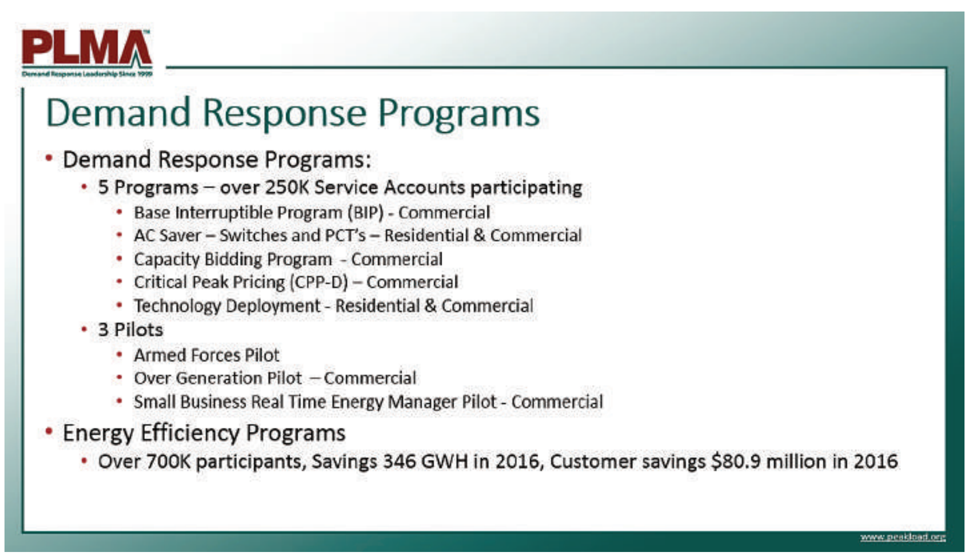
We're starting to see the integration of batteries into our area. We have a 30-megawatt battery in Escondido to the north and we have other batteries that are going in around our service area. We're really interested to see the acceptance of the installation of more commercial and even residential batteries to help us in our loads. One thing that's interesting about San Diego Gas and Electric, our peak load is about 4,400 megawatts. We average during the day roughly between 1,900 and 2,200 megawatts. We're about 10%-ish of the state's load.

So, we're small but kind of mighty, but what's different if you look at us versus PG&E and Edison is our customer mix is really different. We do not have a lot of large, heavy, industrial commercial customers that use a lot of gas. We don't have a lot of manufacturing and processing. And over the years we don't have a lot of agriculture now. Most of our large agricultural users have migrated up to Edison's and PG&E's territory or into Arizona. So, our base is really residential and small commercial businesses, a lot of research facilities and universities. Our biggest customer is the United States Navy, at about 50 megawatts a day on peak.

We're also really a leader in electric vehicles. SDG&E currently has a plan to get 500 EV's driven by employees, and we think we're 20 vehicles shy of having 500 employees driving electric vehicles I drive one now and I love it. Mine's sitting right over behind us in the parking lot, nicely charging away, courtesy of the hotel. We're seeing a lot that–a lot of vehicles growth like with Edison and PG&E. Southern California has the largest concentration of electric or hybrid vehicles in the United States.

For example, at SDG&E, we have electric pick-up trucks that we're beta testing. And even some of our heavy-lift trucks that you see out working on the poles are hybrids. They'll use diesel to get to the site, but once they get to the site they're running off of their batteries. And they can operate even out in east county towards the desert where it's really hot. The truck can sit there all day running their air conditioner and going up and down doing all their work based on batteries. Then come back to the distribution center in the evening and charge up. We also have several battery powered buses that are running around San Diego that we're doing in partnership with MTA. And we'll probably see more of those in the future as we go more and more to an electric vehicle-type environment.

At SDG&E our main demand response programs [Slide 16] are the Base Interruptible Program (BIP) which is an emergency program targeted at our commercial customers. We have rebranded our thermostat and HVAC switch programs to be called AC Saver. Our AC Saver program is our largest program. As you heard Lisa say, we have over 45,000 thermostats registered and growing. It



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also includes, what we call our Summer Saver Program, which is our one-way load control switches that are attached to air conditioning devices. So, to gain about a megawatt of demand response, we usually look at having to install around 2,600 or 2,700 new thermostats.

That shows you the magnitude of what we have to do here to really get the number of megawatts in our PCT Programs to grow. We rebranded our thermostat and AC programs. This rebranding will allow us more flexibility in building programs and allows us to adapt to new technology. The thermostat is king right now but, in several years, it will be the new all home devices, the Alexas, whatever. These devices will be running the entire home, and the thermostat will just become a tool like the hot water heater or the air conditioner. So, we've rebranded our program to allow us the flexibility to do a lot of things. All of our commercial customers last year were converted over to time-of-use rates. We're in the process right now of converting our residential customers to time-of-use rates by the end of 2019.

We're also right now involved in two major IT initiatives. One, on corporate side we're involved in a CIS program that will totally revamp our systems and make our systems function better for the future. And also, on DR, we're going through a DR roadmap right now looking at our systems for the future. Right now, just as an example we have 44 systems used to run our DR programs, it's insane. But we're looking to combine those and make it simpler and make it easier and also, we're trying to look at our enrollment process and other things to make it simpler for the customer and third parties.

We stopped our direct install program for thermostats last year and went to BYOT. So now customers have a choice of right now of either buying and installing an ecobee or the Nest thermostat. We are also looking at different signaling platforms, so we can start including other thermostats that people have into our programs. What we have found is the only way we're really going grow our DR program, is by giving customers choices, allowing them to pick the technology that they're the most comfortable with. Since they've made the investment in the thermostat, they're probably going to participate in a program, and we should get an increase in the kW load drop during an event.

We have a lot of variation in temperatures in our service area. So, what we're doing now with our DR programs is really segmenting the market to look where the areas that give us the best opportunity to see load drop and to get the most kW for the dollar of incentive spend, in order to make us more cost effective.

We also have three pilots going on right now. One is the Armed Forces Pilot, aimed at the Navy. The Navy has been putting in auto DR equipment around the bases. And this is a program that was built to get them involved in demand response by signaling their ADR devices on event days. They have not been a participant because of national security and other operational needs. So, this is a huge step for us and for the Navy to try to get them to participate.

We also have an overgeneration pilot that we're working on now, which is where we're putting battery storage into small commercial businesses that already have solar. This is so we can better understand how to integrate solar and storage and commercial accounts in to our daily operations. And then we have a small real time energy management pilot which is we're looking for cloud-based technologies to help small business understand their energy use.

Martinez: So now we're back home in San Diego and we've traveled around the west a bit, and just to summarize, we've seen lots of different challenges. The emergence of solar, the challenges of being your own grid operator and manager. The opportunities to be able to provide customer choice. So, I'm going to throw a few questions out quickly. Fabienne, You talked about how renewables integration in California creates an opportunity for a new DR, new models of DR where we have the solar. So instead of dispatching the shed where we actually used to turn off air conditioners in the middle of the day, the grid operator could possibly dispatch maybe a "take" signal, or a shift signal. So, can you talk a little bit about how you see those initiatives going forward in the future?

Arnoud: Yeah, so I think a lot of us talked about this for the reverse DR, V over gen pilot. So our version of it is what we call the excess supply DR pilot. We started to think about this in 2015, 2016 when we designed and launched the pilot. And we had a handful of objectives in mind but I'm really going to mention to that pretty much echo some of what had been mentioned on the panel.

One of the things that we wanted to understand better was what was going to be the impact of a dispatchable load consumption or load take on the distribution wires. That's really new for DR, this very local aspect of doing a dispatch. And really, the interesting piece is that the overgen typically happens at the system or sub-lap level. But if customers want to respond and use more they may be limited and their ability to do so varies, for instance congestion or abnormal configuration of the distribution wires.

The pilot is looking at what we might need to change in terms of interconnection process, in terms of information exchange between the DR provider, the ISO, and the distribution operation. Because really what we're trying to do is keep the core fundamental mission of keeping the distribution great, safe, and reliable. The other thing that was really of interest for us with that pilot was the interaction with retail rates, because when you dispatch a load take, you're still very much submitted to your retail rates. You can definitely get an increase on your retail energy, and depending on when you're bid, and when you're being dispatched, you can also get some increase in your demand charges.

We wanted to see actually how customers would come up with strategies to mitigate those risks. And quite frankly, back to my question, whether they would show up or not to take this large amount of renewable thin energy that we have during situations of oversupply. I'll mention two other things to wrap up that question. What is new this year is that the commission the public utility commission in California has launched a load shifting working group that's gonna run for the whole year. And it's taking lessons learned from our pilots, from other stakeholder's initiative to develop the directional or the consuming DR product. And the California ISO is at the same time also having a stakeholder process to look at enhancing their proxy demand response model, or creating another model, possibly to do just that. Not just float shed but float consumption. So, I think we have a perfect storm this year to make progress on that front.

Martinez: Thank you. Rich, when you talked about Hawaii you talked a lot of different types of services that you're going to be providing. But I think it's important if you could help us understand the value of those services. The value to not only the utility, your operating system, and so forth, but the valuation when there is no wholesale market behind you. So how do you value those services?

Barone: Yeah, it's been a big challenge for us. Back in 2015, in a subsequent order to our first preliminary application, the commission ordered us to look at a technology agnostic valuing of services. And it started with really defining what those services are. In a wholesale market, you have the benefit of looking at the instruments that the market calls for. The services are there, and they're defined. But in a place like Hawaii, where we've been running five different systems for many years, we define services for the purposes of planning, and the production simulation models. But to actually put these things on paper, to get planning to agree to what the services are, and how they're defined, and then to get all of the operating groups to agree to those, proved to be a really interesting challenge. Especially because we were asked to do it within a context of DR without our planning folks. They wanted to know, why do they ask you guys to define services, and value them in your docket? It created a little bit of tension actually in the company.

What the process amounted to is a very novel approach, and it sounds simpler than it actually was. Because, right now, in our systems, the generators do all services, and it really just depends on how they're operated. We had to figure out how we were going to go in, and sort of define and isolate, discreetly value, and quantify these different services. And so, we worked with an outside consultant to help us figure out how to do this type of modeling. What we did was we created substitution assets, zero-cost substitution assets at different magnitudes, and deposit them in the resource mix for the purposes of production simulation. By extrapolation at different amounts we were able to see based on the size of the assets if there was any variability in terms of the overall production cost when we took instruments out, and put zero cost plans in and so forth. And what we came up with was a varying value of these services in an annualized basis over a 15-year period, based on assumed resources in the ground, and then planned resources in the ground. And then layered in the demand response potential on top of that, for each of the services. And then we looked at resource substitution to come up with value. So, that's become effectively a very complicated version of an avoided cost in a per service basis upon which we are going to be procuring services into the future.

Martinez: Thanks Rich. Darren, you talked about something that was a little unusual, which is gas DR. And now that you're in your second year of demand response programs in southern California, where do you see these programs expanding, and going? And as a single fuel utility, how would you describe your partnership with your electric partner utility?

Hanway: At least in Southern California, and our service territory the future for natural gas demand response is pretty bright. We've seen a couple utilities in the Northeast that have launched or are launching natural gas demand response program, so there's some mutual learning that's happening at the same time. We've specifically focused on our residential core customers, but I think that where we will be focusing going forward is continuing to scale those residential programs. We will also look at solutions for our commercial and our industrial customers. Most of our service territory overlaps with Mark's at Southern California Edison, and they have a wealth of customers who are already educated on this concept of demand response. They're already engaged with Edison on demand response, and so we are working with them to dual enroll some of our mutual customers into two sets of programs where there will be some level of seasonality; electric demand response primarily in the summer time or in the fall, and then gas demand response in the wintertime. So that's an exciting opportunity for us in order to scale up very quickly. We saw over the course of our limited pilot, about 10,000 thermostat customers in our program. I know Edison has over or close to 60,000. So that's 6 times more than us, and we're working to very easily enroll those customers into our program as well. So that, I think is a near term future for us. Long term we'll make it into pricing signals. We don't have time of use rates. We do have curtailment policies where some large customers receive a discounted tariff over the course of the year. And in the case where a curtailment is needed, their price increases, and some of the experience that we have with those customers is that we've seen a five times price increase. But the customers haven't really batted their eye because natural gas prices, at least in our service territory, are some of the lowest in the country. It doesn't create the economic incentive that otherwise may happen on the electric side. So those are some of the issues that we face and some of the issues that we'll look to address in the future. And so, love any of the innovative thoughts from the room. I'm here all day, I have a couple members of my team here too, who would love to have those follow up discussions.

Martinez: Welcome aboard, and I think you're going to be a fast follower of this organization. And learn lots of different things. I'd like to encourage anyone from the audience that might have a question for the panel to come up.

Ajit Pardasani, National Research Council of Canada: This question is for San Diego Gas and Electric where you talked about cloud-based services for small businesses. Now this is very interesting, because this is one area where restaurant owners, offices, dental clinics for example. I mean so far there has not been much focus on doing the energy efficiency and demand response for those type of customers. The cloud-based services for a small business is very interesting. They also for example, like the restaurants also have these refrigeration doors as well. Where do you see this going, and what has been done so far? And I would love to hear from other utility companies that how are you addressing this area for small businesses as well?

Martinez: So, the question is how are you addressing the small business, because they're actually integrated? They have energy efficiency, and demand response, and not just thermostats, but refrigeration, and so forth, and what are your tactics now?

Mantz: Great question, thank you for asking that. One thing we are doing, we started last year, we integrated with our EE folks on thermostats, Energy Efficiency will offer a rebate, DR offers an incentive. Shosana Pena will be here tomorrow to talk about our retail program where we're doing point of sale now. And we're going to include not only, EE, but DR in that. And so, to try to get these thermostats out to people. And the biggest thing we've found that we have to do more than anything is educate, educate, educate. Because small businesses are scared, they're going through a time of change.

And if you talk to most small businesses, like a friend of mine that runs a couple of restaurants, he said 30% of his cost is energy. I don't know how to manage it, I don't even understand it. Meanwhile he pulls out his iPhone, and he can tell you exactly how many hamburger patties he has in his freezer, what each register is ringing up, what's going through the drive through. I said, wouldn't you like to do that for your energy? Yes! Well how do I do that? Well, right now, it is way too complicated, you have to go to my account, and look up previous day's usage by individual account. But with these cloud-based systems we try make it easier to see their usage, introduce them to programs, and help them grow with it, and they then can learn how to manage it.

Elta Kolo, GTM Research: I think this is kind of a common thread here where you are looking to use distributed energy resources for grid services, right? So, can you talk a little bit about kinda the significance of distributed energy resource management systems? And how you're approaching that type of investment.

Walter: When we talk about grid services, need drives value, and certainly in our context we don't have a lot in terms of the ancillary service needs or a well-planned utility with an IRP process that has had that sort of thoughtful outlook for a long time. We think we do have some value though in some of the non-wires alternatives, but I'll temper that to say that it's only in fairly unique scenarios, right? You need a very high cost traditional solution, with fairly low load growth for people to make a non-wired case make sense. It's not that it doesn't exist, it's just probably something that's more tempered to a once every three years scenario. So, we have our two-megawatt, eight-megawatt hour battery at the end of a distribution line at Punkin Center that is now commercially operable, doing exactly that. And so, there's definitely opportunities in that space, it's just identifying when, identifying the right criteria for when to really sort of dive in, and be able to execute on the topic.

Tyler Rogers, Energy Hub: It's clear there's a lot of very cool stuff going on in the west and even further out in the middle of the ocean. I'm curious, a very interesting topics have come up from reverse DR, natural gas demand response, fast DR. This is all new stuff for a lot of the folks in this room, but to the customers, it's rocket science, or it's Greek. How are utilities thinking about approaching customer engagement to inform customers about these new types of programs, that are counterintuitive to maybe what they'd expect to see from the utility.

Barone: I think our approach at the recommendation of our commission is to seek third-party aggregated solutions. And so, we've taken a hard look at that, we've approached at a number of different angles. But your point is well taken and actually I'll extend this to say that I believe that this is applicable also to things like TOU rates, which I have a whole separate all of opinions about. But I leave you at this, the bundle of opportunities is complex. The solutions that can help customers realize those values are complex. I strongly believe that you need a third party to come in to help effectively market those opportunities; bundle them because a lot of the folks that are putting in equipment and technologies are providing value streams to customers that may or may not have any bearing on some of these programmatic opportunities. So, the short answer is engaging third parties to come in and help with a full supply chain, from the marketing, the education, the packaging, the value proposition, the enablement, and the delivery upstream to the utility is the model that we're pursuing. You help expand market reach beyond some of the core competencies of a utility, which maybe doesn't have the depth of experience to deal with that type of direct customer engagement in these complex areas.

Arnoud: I'd like to add to that, I think in California it's the same. There is a big push from the commission for the utilities to work with third parties. And I think that points to the emergence of a new role for the utility to really enable third parties to help with the customer acquisition and do the things that utilities are not always the best equipped to do.

We're also looking at ways to streamline the customer experience. We've been mentioning how an energy efficient smart thermostat or retail battery can act as demand response. What we're trying to see is how we can streamline again the customer journey when they go let's say for an EE rebate or a rebate for their batteries. How do we nudge customers in the direction of considering a device that also has the ability to do automation with our Auto DR Program? And what is built into the ADR Program is that you need to enroll in an actual DR program. So, it creates that nudging when you're buying this battery, thermostats, to get the automation piece and enroll in DR to provide grid services.

Nick Braden, Modesto Irrigation District: My question is for Kent. I have never heard of a reverse demand response, so I was hoping you can elaborate a little bit more on that. You had mentioned some heated sidewalks and the various ways that you implement that. I'm just curious if that's privately installed or is that a rebate you guys offer or city projects.

Walter: No, so it would be a separately metered service for C&I customers. We have a minimum threshold of 30 kW. But then it would be a meter that, similar to how we can turn on and off meters for new services, be turning on and off that response to negative pricing. And so, it's flexible for what and how the customer defines value. And so, that gives a lot of opportunity for customers to come up with what makes sense for them in their community. But in an area or something that would not exist otherwise, then that's a key criterion there, because you don't want to take away from the demand that ultimately would prevent negative pricing and ultimately clean energy. It's a very sensitive line to walk, but very flexible for what customers might value.

Braden: So, is it more often controlled by the customer, rather than a utility driven program where you turn on the heated sidewalk?

Walter: Yeah, so since it would be responsive to negative pricing, we would turn that on, our load would increase, we'd be able to extract more negative prices within the marketplace. That value goes back to our broader customer base through an adjuster mechanism, then that customer receives that free power. But the critical thing there is it's operating when prices are negative, so it would have to have that direct controlled e-market response.

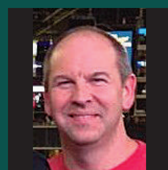
Martinez: That wraps up our western utility perspective. I would like to thank our panel for giving us their perspectives of where demand response is going for the future.

Presentation slides available at
www.peakload.org/assets/37thConf/Western-Utility-Perspectives.pdf

Leveraging Legacy Technology Platforms for the New DER World

As presented on April 17 at 37th PLMA Conference in Coronado, California

Moderator Richard Philip, Duke Energy



Wayne Callender, CPS Energy

Mitch Vanden Langenberg, Dairyland Power Cooperative

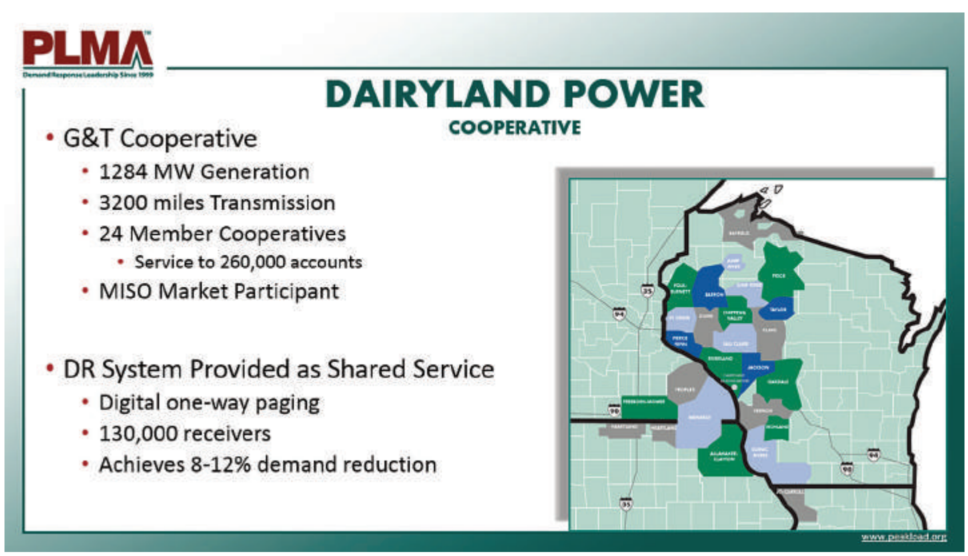
Derek Kirchner, DTE Energy

Learn how utilities are leveraging legacy technology platforms to address new requirements for DER integration, dynamic pricing, and more. Emphasis will be given to the challenges of smaller utilities. Strategies to ensure a smooth migration from legacy to modern technology platforms will also be discussed. Presenters will discuss how AMI and DA systems augment legacy DR and improve its functionality. The session will provide audience members with creative ways that existing resources can be enhanced to support utility business objectives.

Richard Philip: The level of renewables penetration, or adoption of electric vehicles in many parts of the country is at different points. But what isn't so different is even for those at the table in the previous session, with the exception of our friends from Southern Cal Gas, had a lot of legacy programs. Trying to figure out how you deal with programs where they've made investments on in the past–for very good reasons that have been very cost effective, and very useful for your utility, and save money for your customers. How do you leverage those things as you walk forward into a new world? And so, that is what this conversation is about.

Our first speaker today is Mitch Vanden Langenberg. Mitch is with the Dairyland Power Cooperative, that's a G&T cooperative in Wisconsin. His career has its origins in electrical engineering where he's been involved in system protection, balancing area metering, and distributed energy resource interconnections for nearly 12 years. His involvement in DER has continued through his current role as the supervisor of load management for Dairyland Power. He's responsible for overseeing the development and implementation of demand side strategies and corresponding systems. Mitch holds a BSEE from Kettering University. Those of us old enough to remember General Motors Institute, that's Kettering University today. And he acts as the PLMA Board Rep for Dairyland. He also participated in a session yesterday with the DR Integration Group talking about uses of water heaters as we move forward. So, with no further ado, Mitch.

Mitch Vanden Langenberg: As Rich mentioned, Dairyland Power Cooperative is a generation and transmission cooperative headquartered in Lacrosse, Wisconsin. In the G&T model, Dairyland owns the generation and transmission assets that serve 24 member-distribution cooperatives, and they in turn serve the end use consumer. [Slide 2] There are about 260,000 end use accounts throughout the Dairyland service territory, which spans western Wisconsin, southeastern Minnesota, northeastern Iowa, and northwestern Illinois. Dairyland's Demand Response System is a digital, one-way paging system. We have approximately 130,000 receivers deployed across that system that combine to



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provide us with around 8% demand reduction in the summer months, and up to 12% demand reduction during the winter months.

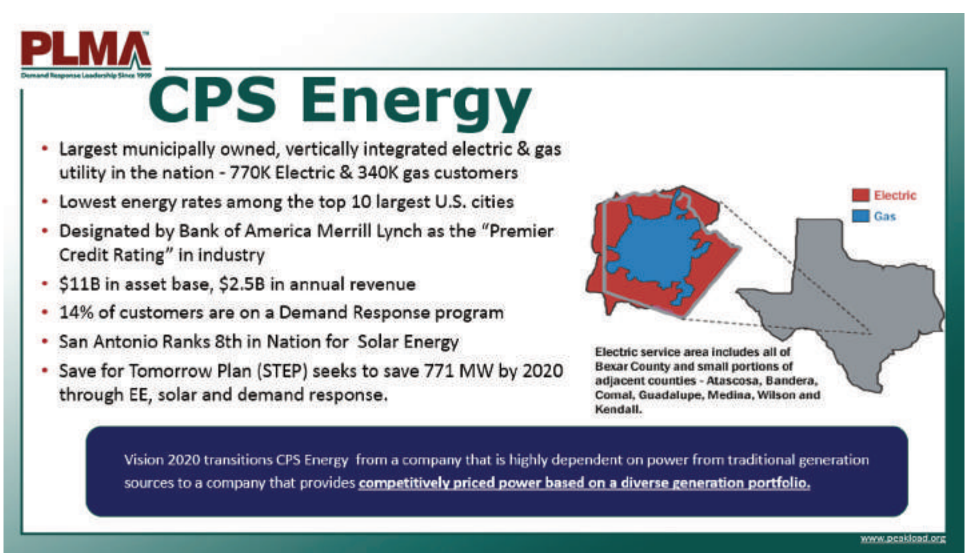
I want to give you a flavor about how Dairyland has leveraged that system over the years and how it has been adapted to implement some more progressive and innovative approaches beyond what its original scope was, which was peak demand reduction. Some of the things we're doing today with that system are real-time LMP monitoring and dynamic event generation to mitigate our exposure to real-time market pricing variability. We've integrated our event signal with the SCADA system to enable conservation voltage reduction events at substations using advanced regulator controls. Also leveraging our distribution SCADA system, we are getting acknowledgment back from receivers deployed across the system to confirm that we have successful propagation of our control signal.

We are leveraging the digital aspect of our system to be able to control devices down to the substation and feeder level. That gives us some value-added operational flexibility. In addition, we are making strides toward member engagement by connecting our system through an API-connected mass notification system that allows us to reach out to consumers through SMS text, email, and telephone communications, informing them and keeping them informed of events on the system. Some of the challenges that we face with operating a legacy system are the ability to measure and verify system event success down to the sub-aggregate level. Also, just the fact that we have aging components and some of those components are obsolete, making them harder to come by for replacement.

One of the interesting things that we face being a generation and transmission cooperative and not vertically integrated is that there is some discontinuity across our member cooperatives in terms of how their retail rates are implemented from region to region. And likewise, there are differences in the AMI platforms that are used by each of those cooperatives. That is another notable technical challenge that we face. I thank you for your time, that pretty well summarizes some of the key program aspects and challenges at Dairyland Power Cooperative.

Philip: Thanks, Mitch. We're gonna hold questions for the end, having a conversation like the previous panel. Second up is Wayne Callender with CPS Energy. Wayne's currently, here's your cool title for the day, Zero Emissions Resource Manager for CPS Energy. He works in the energy market and operations area, and has operational responsibilities for utilities wind, solar, and demand response areas. Wayne actually sits in with the operators to operate their system. He's been at CPS for 24 years, working on a variety of projects including wholesale deregulation, retail market design, automated meter reading deployment, advanced infrastructure, and meter data management procurement and deployment. He's also have been involved in home area network pilots and deployments, load research and analysis as well as demand response. Wayne Callender.

Wayne Callender: Hi, good morning. So, a little bit about CPS energy, if you don't know, we are the largest municipally owned gas and electric utility in the country. [Slide 3] We're second kinda to Los Angeles with electric. We serve essentially the central part of Texas there. We serve Bexar County, the county around San Antonio. You can see the number of customers we have there, we have probably about 770,000 electric and about 340,000 gas. So, it has been some challenges in terms of being both a gas and electric utility. It was very interesting hearing the other panel about some of the gas demand response, and what that focus has been.



SLIDE 3 View Slide at: www.peakload.org/assets/37thConf/Legacy-DR.pdf#page=3

About 14% of our customers are on a demand response type program. And a big chunk of those, probably about 100,000 or so are on a one-way paging system. We've never done switches, we've always done DR through thermostats in San Antonio. That's just kinda the way we've worked on it and so, there's a big lump of load out there that, frankly, it is there and it works. My grandpa was a south Texas rancher, and he was pretty much of the if it ain't broke, don't fix it kinda mentality.

Like Mitch, I'm on the operational side. My colleague over here, Justin Chamberlain, was on the thermostat working group yesterday. The way I like to put it, he comes up with the programs, and then I push the button. And so, from an operational perspective, I'm really looking about megawatts. I don't care if somebody goes around and I send a message and they're flipping light switches, right. At the end of the day if I see the market has a market need, because again, I sit there right with those real time operators who actually dispatch the system–I don't really care where the megawatts come from– if it's one-way paging or whatnot. That being said, we are doing BYOT, we're not as many as 40, I think Brad mentioned 44. We're not up to 44, but we're 10 or so more programs. And so, what happened, the way DR kinda grew at CPS Energy is like most folks, it kinda started over on the retail side of the house, as little pilots and things of that nature, and we were doing our own thing. And it kinda grew, and grew, and grew, until it got big enough to where we actually were no longer just a blip on the system demand curve, but we actually were showing a dip on the demand curve. And so, at that point, that's when operations said, hey, maybe we should take operational control of all that.

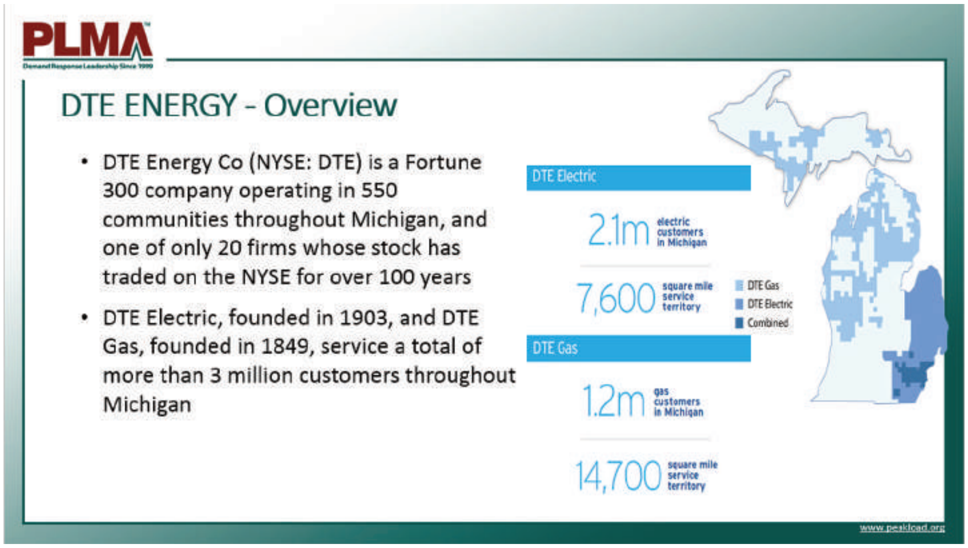
Well, if any of you all have never dealt with your real time operators, they're a different breed of folks, right? So, there's not much that makes them happy, I don't know. The point is they may not be the folks that you actually want just totally in control of your demand response programs, because initially there's a little bit of learning that had to go and take place. Their comment was, well, they signed up for it, I can push the button. I'm like, yeah, but you make them mad enough and they get off the program, then you've lost the resource. So, it's kind of a balancing act. So that's actually where my position was created, was kind of a liaison type position. I've got background in the retail side, that's actually where I came from. And so now, again, my colleagues, my peers, my boss is the director of day-ahead real-time operation. So aside from having to grow a little bit thicker skin to work with a bunch of operators, it actually has been very good because I've kinda educated them on that.

So, the key thing about it is, how does this fit into our legacy systems? It's having that flexibility? A few years ago, we implemented the AutoGrid demand response management system, and what does is it gives us one platform where we can dispatch all these units from. And when you think about it from an operator's perspective, again, they don't care, kinda like me, they don't care where the megawatts are coming from, they don't care if it's the latest and greatest fanciest thing, they don't care if it's a battery, they don't care. They just don't care about it like that, they just want to be able to dispatch it when I say dispatch it.

And so that's been the neat thing about it, is we were able to put it all in one program, so we have a BYOT stuff, we have our paging thermostats, we have our Nest, all of our commercial programs in one spot, not only does it give us good visibility in to it, but again provides that flexibility. So, I'd so that from my perspective, that's the key thing about it, is being flexible because as you implement, you have this legacy stuff, but as you implement BYOT, and the number of programs that you have growing, dispatch can be very difficult. So, flexibility is kind of the one thing I'd leave you with today.

Philip: The third member of our panel is Derek Kirchner. Derek's the principle supervisor of demand management at DTE Energy. And this role, he is responsible for managing approximately 580 megawatts of demand response resources ranging from the residential direct load control air conditioning program to a number of commercial industrial and interruptible tariffs. He's charged with developing DTE's Distributed Energy Resource Strategy for both the existing demand response programs and the integration of new technology-based programs, such as programmable communicating thermostats and battery storage. Derek is currently the Vice Chair of PLMA and is an advisory council member on demand response in Smart Grid for SEPA. He has worked in several areas of DTE over the past 19 years, including customer marketing, generation optimization, corporate strategy, integrated resource planning, and regulatory pricing. He's got a BA in business administration from the University of Detroit Mercy and is a certified energy manager. So now I give you, Derek Kirchner.

Derek Kirchner: Thanks, Rich. That's still a lot to live up to most days. So DTE, been around and had demand response programs since the late 60s. [Slide 4] So, when you talk legacy programs, I have the legacy of the legacy programs to deal with. It's much like these guys up here, one-way radio paging, AM/FM signals, 56K-modem technology. It's hard to find parts for our technology. I started working on demand response in about 2006. And in Michigan we peak at about 10,500 megawatts in the summer and about 7,000 in the winter, so it's all residential AC load.



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The system currently is set up separately metered, only controls the outside compressor in 15-minute-on, 15-minute-off increments. Customers rarely know you interrupt them because it's just a long duty cycle, you don't get warm in the house, the fan is still running, everybody's great. But we haven't had a lot of system need in Michigan. We were long in generation in the 90s and early 2000s. The economic downturn hit us hard in 2008, so there was capacity. And much like Wayne said, if it is not broke, you don't fix it.

So, we would bid it into the market as the residential AC program at 200 megawatts year over year over year, we never had to use it. Then one year we had to use it, and we pushed the bottom then we got about 60 megawatts, and everybody went, what happened, right? This stuff, it worked for 20 years, and it should work like it did 20 years ago. We started looking at it and in 2015, we started a program to go out and take those one-way switches out of the field and replace them with new two-way ZigBee-enabled switches that ride on our AMI network.

We're fully deployed with an Itron AMI network at this point. I've got 275,000 switches I have to replace, we've got about 80,000 done through this year, after three years, and so I got another almost 200,000 to go. We started sending folks into the field and try to do these replacements. And the switch needs 24volt power from the compressor to be able to work. About 35 to 40% of the units we go out to don't have power to the switch, and that's customer-side of the equipment. That's not utility-side of the equipment.

So now at least we've figured out what's going on. We have to go out there and try and convince customers to put money into and invest in the system that they might not even know they have. They moved into a house, with a system installed in 1972, and have no idea what it is. Now we have to convince them to hire an electrician to fix this thing that they didn't know existed and don't know what it does. They've never suffered an interruption, because the pager doesn't work… and they are getting a 20% rate discount on that usage, so it's kind of the best of both worlds for them.

So now, we're in the midst of replacing that system, and will be getting back the capacity that we now need to bid into the market and get us back to where we should be. In addressing some of the lost revenue issues on the utility side–we have the ability to go down to those individual devices at a specific meter and just interrupt that house if I need to. We can go down to the substation level, we can get to the circuit level, or a zip code level. And now we've started to look at doing things for a non-wires solution, non-wire alternatives. If the distribution guys get a loading issue that's localized, we used to run a van out there. There is a van that DTE built, it has a radio transmitter in it, you put the antenna up and it dispatches a two-mile wide radius. Now, rather than going out and running the van, we can just push it from the control room. So, the legacy stuff is great. Again, we want to be able to push that button but you got to know what you're getting on the back end. Now we are turning it into operational DR and using it more than just once every 10 or 15 years when it gets really hot. We want to be able to use this stuff almost every day if we can. We're taking that legacy approach and moving it into at least the 20th century now.

Philip: Thanks, Derek. So, a couple questions to warm up. One, Wayne, you've mentioned legacy system, all right? And it seems like some of your initiatives are actually younger than a lot of ours, but you're already talking about legacy systems. So, my sense is that maybe the definition is changing on us. Do you want to elaborate on that any?

Callender: Right, because I mean I was looking at it the other day, I mean, just time flies, right? When you're having fun. And so, we were looking at, one of our systems is legacy, it's a ZigBee cellular system that was put out in 2011. So that thing's already seven years old.

And I would just submit the definition of legacy, with the pace of technology and the way things are changing so fast and BYOT and customers wanting this and wanting new things, but, again, I still want to keep the megawatts from the old stuff. I just challenge, be careful what you think about legacy, there is stuff from the 60s, but heck, I would even say that stuff that's even just seven or eight years old or even, heck, even a couple years old now may even be legacy. So, again, that's why having that flexibility, having some type of a platform, having where it can easily connect in, you can plug and play kinda thing, with the different programs, I think is something you need to look at. When you look at this plan, I was like, well, just think about "what is legacy?"

Philip: So, we have three different types of utilities represented here today, a generation and transmission cooperative, a municipal utility, and an investor-owned utility. But essentially, for a lot of things we're talking about, it's really about change–and change management–right? So, can you guys talk a little bit about what the challenges are within your organizations? With this evolution that's going on. I mean we're talking about, it's one thing to get people to understand what we've been doing. And that has its own interesting challenges, but as we move forward, I think the level of engagement and who we're engaging is a changed situation as well.

Kirchner: Yeah, just to jump onto Wayne's point about "how do you define legacy", I think at an investor-owned utility , half of the legacy definition is, "this is how we've always done things". You have to get to know the generation optimization folks, and the real-time traders doing the dispatches, and the involve them on the distribution operations side of the house. Having those internal conversations, getting those right people at the utility to the table, that's the true definition of legacy to me. It's not the equipment. You're right, technology is going to evolve faster than we can keep ahead of it. But if you can get that change management and business process piece done, you're going to be ahead of the game. It doesn't matter what's connected at the end of the line, so long as you got everybody marching in the right direction.

Vanden Langenberg: Yeah, I think one thing that's really key for our business model, we have a 24-member cooperative. You can be certain that when we try to coalesce around a shared vision, there's going to be diverse perspectives about what we should be doing with a future system. That's definitely one of the big challenges, and I feel a big responsibility myself to try to provide input and feedback about what's happening in the industry - provide them with that insight so we can identify objectives. What are the fundamental objectives that we want to accomplish and what's it going to take to get us there? One of the really big things that I think will help us get there with our business model is interoperability and the ability to adopt different disparate systems in unison with one overarching system that can help manage it all.

Callender: I think so. I'll talk a little bit about the funding, right? So, kind of backing up, we're a municipal utility. And the way that we fund our demand response programs is, in 2009, we have what they call the save for tomorrow energy plan, STEP, that our city basically created the ordinance that lets us recover the cost of energy efficiency and demand response through our fuel adjustment factor.

Basically, we spend it this year, we get audited, and then we recover it the year after. And so really, what you have to look at, and this is something more from Justin's perspective that we really need to look at is the cost-effectiveness test, right? So, I mean, we are finding like most folks, like with you, that the one-way pager was almost fully deployed on the AMI System, Silver Springs (now Itron) system that'll be almost fully deployed out there.

And what we're finding is, yeah, that when we do push the button, we're not getting the response because we'd be doing thermostats. Most of those thermostats have been replaced, so people replace their systems. And I'll say it, it's the HVAC contractors that just go out and put their own system in there, but that's another story. So, my point is, is that when you've already spent from something, I mean, it makes sense on some of the stuff that it's not working on. But on the stuff that it is working on, how do you make those cost effectiveness guidelines that you've already kind of spent the money? We've had a big push since 2009 to put these, even install on one-way pagers out there. And so how do you make the business case work is also key from, not only with all the change management, but how do you make that work as well.

Philip: Mitch mentioned that with 24 electric cooperatives, there's some diversity of what goes on. I remember when I'm working my first demand response project in Indiana, we're working in partnership with Wabash Valley Power there. And the guy over at system operations said, with all the cooperatives that we serve, there's three camps. He said there's a third of them that will do pretty much whatever we recommend, thinking that we're trying to do the best for the system and their customers. There's a third that will take a wait and see approach. And there's a third that will run screaming in the opposite direction. And I found that useful over the course of my career. Any time we were trying to implement, even within our company, things out to the field, out with other operating units, or whatever the case may be, that there's always that type of thing going on. And it is an extra layer of complexity when you're G&T. Questions from the audience, please?

Mark Martinez, Southern California Edison: Sure, so I think it's not so much the technology. The things that have changed over the years have been the communication transport layer like paging, 154-megahertz, 900 megahertz. Now we've got cell phones and Wi-Fi. So those all have a different sense of reliability too because the utility doesn't control the Wi-Fi network. And they don't have ownership of certain things. But I guess that's why some utilities will still maintain those transmission towers and things for the reliability. What's the philosophy on trying to maintain a control over what I would call the transport layer?

Kirchner: I'm just glad we're transitioning to anything that a coffee can can't stop at this point. That's one of the other things we find a ton, is you just wrap that thing in foil and it doesn't work anymore. But you're right, there are gonna be issues with whatever kinda communication technology we look at. But when I'm looking at something like Wi-Fi and we're launching a programmable communicating thermostat program, okay, I can kinda do a health check ahead of time. I can see if that thing's working or not, and then go into the portal and diagnose. All right, if it's not connected, when did it drop off last? It's not just having the technology layer to dispatch it, but it's getting that information back, even with the new two-way switches. We're gonna health check at the beginning in the season. I can figure out if it doesn't have power or if it's just unbound, and if it's unbound, from the desk I can send a rebind signal to that meter and to the device and get them to sync back up again. It could've been there was an outage, it could've been there was whatever. But I can tell–if the rebind works, I don't have to do a truck roll. If the rebind fails, then I have to send somebody out there to see was it a power issue, or was it something else going on. So as much as it's the communications protocol, it's having that data to do better business intelligence on and not rolling a truck every time we think something's broken.

Callender: We've looked at it from a cost-effective perspective in that we're pretty condensed in that part. Our service territory is not really spread out, so we're mainly urban. So, keeping up, for example, the paging network and things of that nature, well, we don't do that. But it's still been kept up enough to where, again, it's a cost-benefit kind of analysis. We're tending to go away from the self-install mode into the BYOT-type mode. And as such, when you kinda balance that out, yeah, you have some maybe Wi-Fi connectivity issues, but you balance that out for the fact that your install cost is gone from a few hundred dollars to whatever you rebate the customer. So again, you kinda just have to also look at just the businesses, right, the business case. What do the pluses and minuses look like there?

Vanden Langenberg: I think we've seen a lot of interest in progress toward reducing the install cost or in eliminating the need to roll a truck, and there are some really good financial incentives behind that. I think on the other side of it, we have a real case for operational benefits that have a need for reliability in the transport network. I think what we are going to see is a resurgence in some ownership of that transport layer and increasing the amount of intelligence that we have at the grid edge. Those are some of the considerations for our cooperative.

Elta Kolo, GTM Research: My question is around kinda the participation for an ISO and RTO markets. And what hurdles have you faced with kind of the telemetry requirements, and the Measurement and Verification requirements for your programs?

Kirchner: The switch program goes in into the MISO market, and the PRA auction as an LMR, load modifying resource. As we started to dispatch these more and get reliant on them, more time is spent on M&V and data analysis of what is being forecasted. Here's what the first test event showed, proving to MISO weather adjusted temperature normalized, how I can get the actual credit that I'm taking. So that's been evolving as well. It's no longer, "just trust us"–everyone is making operational decisions. Our AMI is fully deployed so I can get real-time interval data–we have a house meter for the full load, and a separate meter for just the AC compressor, so I can easily pull that data. I can verify the hour before, hours during, and hour after to validate the drop we registered in the market.

Callender: Yeah, for us, our M&V as I said before, we have an auditor comes in and has to essentially audit it. And that's obviously where AMI has been really effective in helping us do the M and V analysis on our meters. I'll be honest with you. We try to stay away from some of the, Programs just because you can stay away from the telemetry. In Texas, we pay for transmission based upon the 4CPs, and that's a pretty good money right there, savings, and you don't have to prove it up. I mean basically the other thing I need to mention, we're not opted into the Texas market. We are still a vertically integrated utility. So, we have battery meters, so anything we can do to reduce that battery meter reduces our TCOs. So, there's several customers that have wanted that have wanted to participate into the ERCOT market and we're working on facilitating them, but mainly we try to keep the data requirements mainly internal to CPS.

Vanden Langenberg: As I mentioned earlier, M&V is one of our great challenges, and so right now, we do not enroll any of our demand response capability into the MISO market, but we do respond directly to the price signals that are sent to us from MISO. We respond to LMP pricing and to the cost impacts associated with coincident demand.

Nick Braden, Modesto Irrigation District: We have a legacy DR program, legacy being a paging structure. And I've been recommending to management ways we can improve that, jumping to the thermostats or whatnot. In your guys' experiences with your legacy programs, how are you guys doing the M&V to basically decide when to let a program die, when to let it go, and when to, I guess, fold it into your demand response management system so you can operate it in tandem with whatever your new stuff is?

Kirchner: You've brought up the business case a number of times, and I think that's kinda how you figure out where the rubber meets the road, and we at DTE just started going through an integrative resource planning process. We have another IRP due in 2019. If it fits in there and you can put your cost in there and there's some avoidance, whether it's today or 15 years down the road where you're delaying a plan build or delaying something and you can justify the cost. To me that's bottom line, right? If it is in the best interest of the utility and the customer at the same time you can make that investment and that's probably the one of the easiest ways of go about it.

Callender: I'm a Walking Dead fan and all to say that those zombies don't have anything on our programs, right? They just keep going, walking around just because you know, but again they're producing the megawatts. So that's something that we kind of looked at right. We're kind of making sure when and again it goes back to the business case. It goes back to when are they the effective and as Mark mentioned, it also looks at what are the news technologies out there? What are the new abilities of talking to these things and whether they maybe a minor retrofit or a pretty small retrofit especially if you're doing irrigation type stuff? Could you go out and swap out the pager? Frankly there's a lot of cool stuff on the cellular side. I know we talked a number of years ago cellular was kind of expensive but I think the Verizons and the other folks of the world have come down on those costs.

So, it's just a matter of keeping your kind of ear to the ground and seeing what's out there, looking at the different, talking to different people about what their different technologies are. And then figuring out when does it make the most sense that you're not getting the megawatts that you need versus switching over to a different program. And a key thing, right, is also about figuring out how you can phase it in because that's the other problem. Nobody, I don't know about y'all, but it's real difficult to get that kind of capital dollars and frankly, getting IT's attention for that much time and that kind of stuff. So, you kind of have to be a little strategic on how you implement these things as well.

Vanden Langenberg: For us, I would say that we look at whether the system is meeting the objectives and whether we are getting value out of that system or if it is costing us too much. As we look forward to integrating new technologies, there will definitely be that transition period where we need both systems operating side by side. As we implement that new system, I think that is where marketing is going to play a big role in ensuring that we get uptake on that new system so that at some point, the legacy platform does transition to a planned obsolescence, and it doesn't become that "zombie" that was previously mentioned.

Philip: Please join me in thanking our speakers.

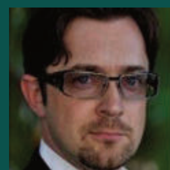
Presentation slides available at
www.peakload.org/assets/37thConf/Legacy-DR.pdf

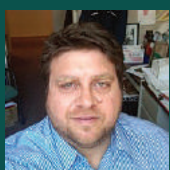
The Future of DER: Energizing the Smart Home

As presented on June 26 for a joint webcast with Parks Associates


Tom Kerber, Parks Associates


Rich Barone, Hawaiian Electric Company


Michael Brown, Berkshire Hathaway NV Energy and PLMA Board Chair


Tony Koch, Bonneville Power Administration

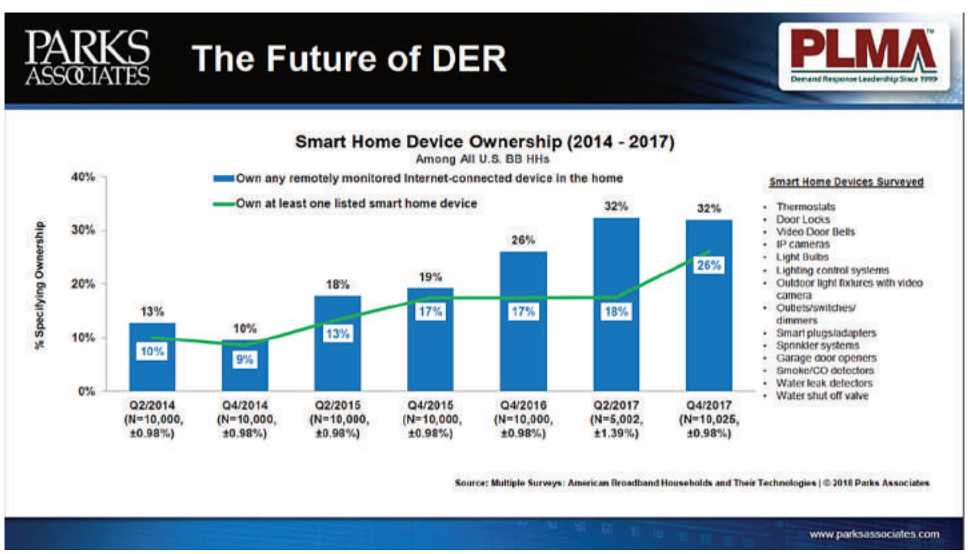

John Powers, Extensible Energy

This webcast analyzes consumer adoption of DER (distributed energy resources), including solar, EVs, and smart home solutions, as well as strategies to integrate these solutions into energy services in order to provide cost savings and better shape the household load. Currently 26% of U.S. broadband households own a DER product or an electric vehicle, with adoption at 41% among heads of household ages 18-24. The popularity of these solutions among younger households indicate their adoption and usage will continue to increase as these consumers age and as younger generations move into their own households.

Utilities see multiple challenges associated with the increased adoption of DER solutions, including capacity constraints and grid and power reliability. Utility executives have signaled the need to invest in grid intelligence to manage DER solutions to secure the grid from cyberattacks. Many new smart home solutions, combined with data analytics and grid intelligence, provide a granular view of household devices and their energy usage to end users, households, and utilities. This information opens opportunities to recoup grid investments and create new revenues through DR participation, energy management services, and partnership opportunities between smart home manufacturers and energy providers.

Utilities can also leverage DER and smart home resources to provide actionable intelligence to end users on how they can save money and energy and also become more energy independent. This webcast looks at the market for DER, its growth trajectory over the next several years, and strategies for energy providers and other smart home and IoT providers to get ahead of adoption and build business strategies around the integration of these solutions with the grid. The event examines the potential for smart home participation in the wholesale market, and industry experts also discuss the possible impacts of proposed tariffs on the U.S. solar industry and the rates of adoption and installation.

Tom Kerber: Distributed energy resources are being sold and installed behind the meter at increasing numbers. And they create both obviously challenges and opportunities. This is a chart that shows smart products are entering the market in increasing numbers. [Slide 4] Today, 32% of households own at least one product that can be controlled via smartphone. And amongst the home automation category, roughly 26% of households own at least one of these connected products listed to the right. A thermostat is one of the leading categories, roughly 13% of households today own a smart thermostat. This is obviously a challenge and an opportunity both because as both the breadth and the number of smart products enter the home, it opens up new possibilities for demand and management.



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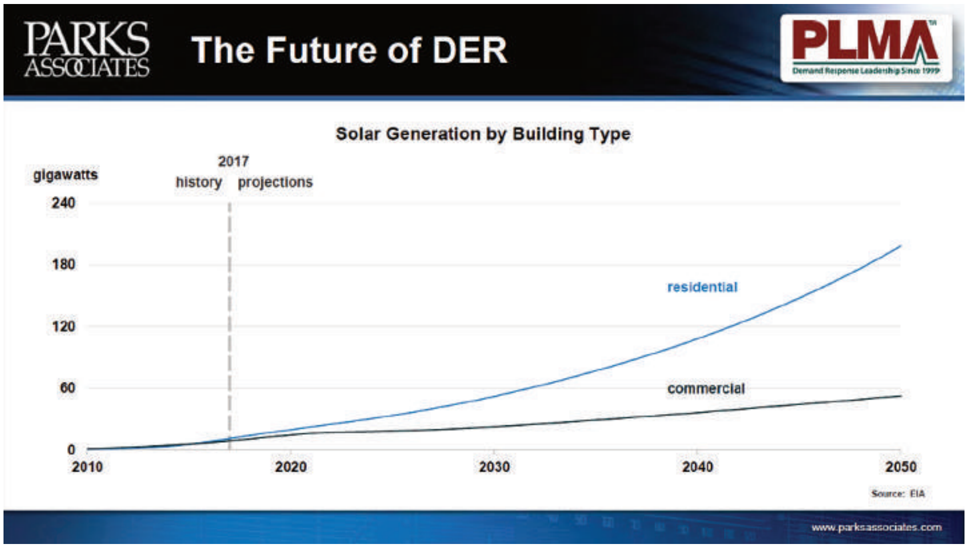
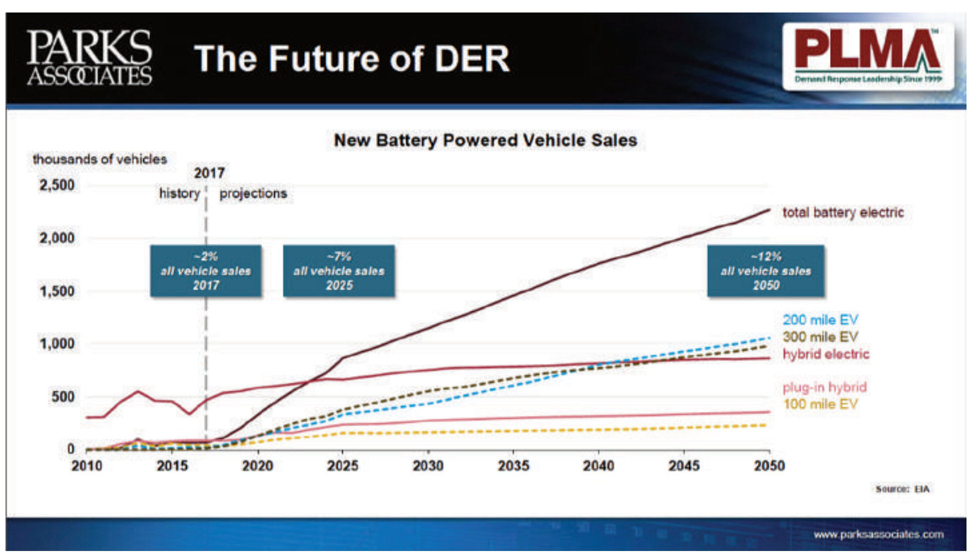


SLIDE 5 View Slide at:
www.peakload.org/assets/docs/The-Future-of-DER-webcast.pdf#page=5

Historically, residential load has been kind of, it is a firm load. But obviously, when you have connections to different devices like that, that is now a bunch of our movable resources. Now, at the same time, rooftop solar deployments are also picking up steam [Slide 5]. According to the EIA, about half of the small-scale PV installations are rooftop. And going forward, EIA projects that residential will outpace commercial applications by more 350% through 2050. Again, simultaneously, the plug-in electric vehicles and battery electric vehicles rose by over 17% last year. [Slide 6] So roughly 200,000 vehicles were sold in 2017. And the total number of plug-in electric or battery electric vehicles on US highways rose to roughly 740,000 at the end of 2017. You can see the chart here. Obviously, this is, again, both a challenge and opportunity.

Growth in electric vehicles, growth in roof top solar, growth in smart home solutions, right, they present individual challenge and opportunities, but collectively, right? The fact that they're all happening simultaneously adds another layer of complexity and challenge. And so, when you look at all these changes, the question from an energy provider, right, is, how do I align the product operation to the needs of the utility?



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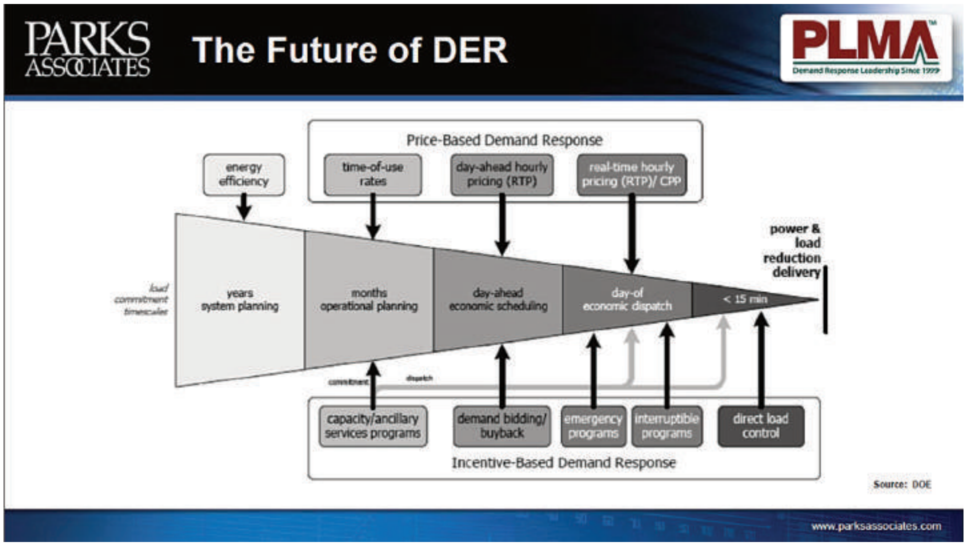
www.peakload.org/assets/docs/The-Future-of-DER-webcast.pdf#page=6

The Department of Energy has put together this slide, and perhaps you've seen it before, it's been around for many years. [Slide 7]

Talking about how, for those who are not in the energy industry, right, the idea that supply and demand have to be matched every second of every day. When you turn on the light switch, right, there has to be electrons available to fulfill that load. And there are many mechanisms that energy providers use to make sure that the supply and demand is matched. In terms of peak load management, right, there at the top of the chart here it's showing energy efficiency and different pricing-based mechanisms. Within those pricing mechanisms, there might be time of use, grid of peak, real-time pricing. And at the bottom of the chart it shows different incentives, right, where you pay people not to consume energy during these peak periods. Now, each one of these individual boxes, there's a lot of options, and each utility is its own unique kind of entity. It may be peaking in the summer, it may be peaking in the winter, right? Each one has its own needs, and it wants to align the consumers' interest to that of the utility. So, if you think about each one of these individual boxes, right, there's a lot of design choices, there's a lot of, I'll say individual rules for participation, right, that adds kind of another layer of complexity. And when you think about the number of utilities that are out there, and each one kinda making up their own rules or designing their own programs around this. If you're the outsider, if you're the



SLIDE 7 View Slide at: www.peakload.org/assets/docs/The-Future-of-DER-webcast.pdf#page=7

smart home industry, if you're electric vehicle manufacturer, if you're a rooftop solar vendor, you're looking at this and you're seeing a lot of complexity. So today, hopefully, you'll have the speakers demystify or provide some kind of clarity, or maybe not, right? But try and provide some overview of what's the perspective of the utility industry, and how we might align the interests of these products and services to those new to the industry. So, with that as a brief introduction, I'd like to ask each of the panelists again to give their perspective and an overview. And we'll start off with Rich Barone, who's the manager of Demand Response at Hawaiian Electric Company and is also the PLMA DER Integration Interest Group Co-Chair.

Richard Barone: Thanks, and good morning, everybody. I'll just give a quick thumbnail sketch of me personally and then what's going on here in Hawaii. I've been in Hawaiian Electric for three and a half years now, and had been a consultant with Hawaiian Electric for two years prior. On a personal level, my background really is software technology, energy hardware technology, consulting, entrepreneurship, and community outreach. And I will tell you that I use and rely on all of that experience in this role. As you can tell from the background on DER and DER populations and integration, you sort of need all of those skills to make a workable solution set. And at Hawaiian Electric, we were really charged in 2014 with launching an integrated demand response portfolio. That truly looked to take a technology agnostic approach to delivering necessary grid services to our system operators. And in turn providing customer choice and empowerment along the way. And that task was sort of driven or underscored by the fact that the intent is to enable the integration of more renewable energy in our system. And shortly after that order was issued in 2014 to launch or pursue an integrative demand response portfolio, the state legislature mandated or passed a 2045 100% RPS for the state. So, kind of stoked the flames a little bit of our situation. As most of you know, we not only have a lot of rooftop solar around the state of Hawaii, but also have very aggressive targets for electric vehicles. So, we're early in the throes of this stuff and figuring out as we go and starting with system level services and migrating our way down systems, sort of the distribution or circuit level services, which is gonna be even more challenging and complicated.

Kerber: Next is Michael Brown, Michael is the Manager of Demand Response & Distributed Energy Resources for NV Energy, and is also the PLMA Chair.

Michael Brown: Thanks, Tom. I'm very happy to be in the call today representing NV Energy and PLMA. So, for a brief background, NV Energy is a vertically-integrated utility in Nevada, and we serve approximately 1.3 million customers. We run a portfolio of energy efficiency and demand response programs. We've got about 200 megawatts of dispatchable peak demand reduction, and that's supported by an enterprise Demand Response Management System. I did not say DERMS, I said it's DRMS, and moving from DRMS to DERMS is something that we are heavily interested in. And we've got a number of teams of the company that are coming together now, for about a year, in response to some legislation that says thou shalt file a distributed energy resource plan. And our first distributed energy resource plan is due in April of 2019. So, the teams that are coming together now include my department, demand side management, renewables, distribution planning. We've got a new department integrated grid planning, and of course, resource planning. These are some of the cross-functional teams that are coming together to get ready for the filing and prepare ourselves for the future of DER, right? So, we're very interested in it, as are many utilities. I would say that at PLMA, we've got a lot of utilities, a lot of service providers, a lot of technology vendors. We have over 140 member companies now with deep load management expertise. And many of these companies are focused on this evolution from demand response programs and technologies to understand how best to incorporate this wider set of distributed energy resources that we're talking about. And obviously, we see a range of opinions in the different approaches, and of course, we too at PLMA, we're bringing teams to work together to share best practices. One of those ways that we do that is through our interest groups, hence our DER integration interest group, chaired by the gentleman on the call with us today, Rich Barone, and John Powers. So, we're very happy to be on the call today, Tom, thank you.

Kerber: Next is Tony Koch. Tony is with Bonneville Power Administration.

Tony Koch: Thank you, happy to be here. Just a little bit about BPA, it's a wholesale power marketing agency, federal. It covers four states of the Northwest, Washington, Oregon, Idaho and Western Montana. And we have been traditionally demand-rich with our hydro, but in the past ten years or so, the capacity needs have increased, our capacity availability is beginning to shrink. In the last five or so years, we've been actively pursuing pilots. So, we don't run programs yet, but we're seeing the need for demand response and load shifting coming. We've been actively involved in piloting of both industrial/commercial and residential projects. And doing a lot of benchmarking, reaching out to other parts of the country, Hawaiian Electrics, and NV Energies, that are doing stuff and learning from them. And a couple takeaways I want to just leave you with is for residential, leveraging the customer's Internet. Broadband is a huge value opportunity, but it's also been a huge challenge. We've learned that for a utility-grade system, a 24/7 kind of operation, it's very challenging to lean on the customer's Wi-Fi, although it's very attractive from a cost perspective. There are two things I want to say there very quickly. One is, we're working with EPRI. We're participating in a persistent Wi-Fi project that EPRI has put together that looks at taking standard modems and creating a physical and firmware firewall within the modem. This would allow a VPN within the modem in a standard, mass market product offering–not a special widget. That's future work, that's work that still hasn't started, but it's about to start later this year.

Another project that was also initiated with EPRI, for the last three years, is a BPA funded project to further the use of the demand response standard CTA-2045. If the organizer could, yeah, push one more slide, I've provided here the front cover of the standard. [Slide 11] It's an ANSI and it's CTA, (Consumer Technologies Association) standard for a modular interface for demand response type products. And I'm showing here two heat pump water heaters that are part of our studies right now, that have the port. You can take a proprietary port in a tank, translate it to the open port with the CTA-2045 standard and then install a communication module of your choice, whether it's radio, Wi-Fi, or your AMI system, what have you.

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So, I just wanted to give you those two thoughts in terms of leveraging the Wi-Fi, but also improving the communications by an open standard such as CTA-2045. These are going to be critical for future integration of different products and different technologies, and retaining the diversity for the utility on the back-haul communication. In other words, how we get the data from the customer's home back to the utility and vice versa.

Kerber: Next is John Powers, who is with Extensible Energy and is also PLMA Group Co-Chair.

John Powers: Thanks, happy to be here. Extensible Energy provides consulting and technology solutions to utilities and their customers and to third party market participants, all addressing distributed energy resource integration. We work in pricing, program design, program evaluation, and technology development and deployment, all designed around making flexible loads into grid resources. I managed several programs recently for the Department of Energy around the topic of combining solar and wind flexibility, that includes demand response and storage. We like projects that allow us to work on both sides of the meter, to improve grid reliability while incorporating more distributed resources. I'm here today in my capacity as Co-Chair of that PLMA DER integration interest group we talked about. That's where we facilitate an exchange of information between utilities and DER providers, including those delivering smart home products. So, I'm excited about today's webinar. We do webinars like this one, we have a great online community. We also host two amazing workshops per year at the PLMA spring and fall meetings. Our next one is in Austin, Texas, on Monday, November 12th, and you do not want to miss it.

Kerber: Let's start then with the Q&A. I described kind of the adoption of rooftop solar, smart home, electric vehicles, right? We're seeing significant growth across multiple categories. Let's start with the perspective of the utility, though. So, what is the biggest challenge from a grid operator associated with those expanding adoptions? Rich, I know you're the tip of the spear when it comes to rooftop solar. Maybe you could start us off on this discussion.

Barone: I'll give a perspective from what we consider to be our biggest internal customer, which is System Operations. And at the end of the day, those are the folks that we have to develop solutions for. And we have to make the solutions be operational generator-like tools for our operators. Having said that, one of the largest challenges we face is visibility. On the one hand, Hawaiian Electric does not have an advanced metering infrastructure, we don't have smart meters. And secondly, a lot of the legacy rooftop PV systems that we have, we really don't have any insider visibility in terms of the production. We can infer production but we can't really see it. And so just from the perspective of status, availability, and ultimately control, at present, we're challenged with that as a kind of an operating system. I think part and parcel of that isn't just your visibility that you get at the device level or even at the home or business level, but also, the company moving into the future, you also need visibility at your circuit level. On the company side of the meter, we've got to continue to expand our telecommunications infrastructure, our SCADA, our distribution automation systems as well. So, a lot of moving parts that have to get put in place to give our operators the degree of what I would say is sort of reliable status availability in control of these assets. That's one pillar of the challenge. And the other pillar of the challenge is, generally speaking this is not a mystery, but you do have variable production. From day to day, from hour to hour, from ten-minute window to ten-minute window. PV in particular produces at different levels at different parts in geographies across your system. And even though we operate in the context of multiple islands, there's still no uniformity in terms of production patterns of these systems. So strictly talking about PV, which I think was your question, those are some of the fundamental challenges that our operators face.

Kerber: I appreciate that. Michael, do you want to weigh in on this? What do you think your biggest challenge is from NV Energy's perspective?

Brown: Well, I'm gonna back Rich up because he gave an excellent description. But I can pile onto the challenges a little bit if you like. And some of those that come to mind are that the DERs are simply forcing the utilities and the operators to think differently and operate in a different way. And so that implies a whole change management requirement. That means looking at new technologies, changing the way that we plan, changing the way that we do our business processes. Those are significant organizational challenges that I'd just like to set forth on top of the pure technology challenges that Rich had for us. That's what comes to mind.

Kerber: Can anyone speak on the challenges of electric vehicles? Obviously, those assets, if I had two electric vehicles in my home, basically adding another home's worth of load as to the capability. I know those loads move place to place, so I can charge them at work or charge them at home. From a planning or from an operation perspective that adds incredible complexity. I just want to kind of understand, I don't know, how utilities are grappling with that challenge.

Powers: We see a lot of that. I liked your opening slide, but I actually think that the penetration rate of electric vehicles will be faster than that from what we're seeing. And the charging patterns, there have been some early studies, but there's nothing that suggests that we know very much about it yet. Because the folks who have bought electric vehicles so far are early adopters, they're not mainstream. And the mainstream is gonna come, and it's gonna come quickly. And so, the utilities have a lot of justifiable anxiety around how you manage the charging patterns of millions of new homes. As you say, it's as big as a house, appearing on the grid, in surprising places, at surprising times. So, there's a lot of work going on now around fast charging at very well-resourced locations on the distribution grid. There's a lot of work going on in rate design to encourage charging during advantageous times. There's reason to think that the result could be very beneficial to utilities if the process is well managed, because you can charge a car overnight, you don't have to charge it during the middle of the day. You can flatten out load profiles where otherwise there'd be big dips. There's lots of opportunities here, but I have to say it's early days, and things could go terribly wrong if millions of vehicles appear, and are charged in uncontrolled ways.

Kerber: Tony, I know you have a unique perspective, as you mentioned, a wholesale power provider. What's your view on this question about the biggest challenges?

Koch: It's early yet for us. We have not experienced palpable DR issues to date but I think it's important we're learning from our neighbors. California is experiencing something similar to Hawaii with renewables, and I think we are in a learning mode basis but knowing that it is coming. So, it hasn't manifested itself aggressively yet, but we know it's coming.

Kerber: So, the next question, so I think it was great to understand visibility, understand the challenges of variable production and then the internal challenges of change management. This question is just kinda thinking longer term, right? So, is there a clear vision where what does the grid look like, longer term, right, after we have wide-scale rooftop PV, EVs, and smart home solutions? When those solutions are developed broadly, right, so 50% of homes have these products and services, what does the grid operator look like at that point? Michael, do you want to start us off on that?

Brown: Sure, you're asking if there's a clear vision, and I would say there's definitely an emerging vision. And with greater levels of clarity in some areas versus others, right? So, we have to keep in mind that this term "grid operations" is quite broad. And it can cover a range of areas which quite frankly mean different things to various stakeholders. So, if we take a technology only perspective, I think there's a lot of clarity emerging around the need for new enterprise systems for operators, such as the need for a DERMS, a distributed energy resource management system, be it an extension of an advanced distribution management system or a DRMS or both of those coming together. And this year, we're seeing some important interconnection and communication standards that have been published. So those are certainly providing more clarity in the industry that's going to help utilities interconnect with behind-the-meter devices. But there are still a number of areas that are a bit more grey. I would point to in this emerging vision, and include questions about, what are the best ways to accommodate the differing needs of the bulk power system, right, at the wholesale level and the wholesale market versus the local needs of the distribution system.

So, if we go back to that slide that you showed, Tom, earlier when we're looking at months out or a week ahead, or even a day ahead, we tend to think about trends in the wholesale market and how can we apply class-based tariffs to help us address those issues. But then when we get into the local distribution system for reliability reasons and for day-to-day operations, right, the time-frame with which we have to interface with behind-the-meter devices or distribution-line devices becomes much, much quicker. Tariffs for an entire class of customers are spread across different distribution circuits, then we have to look at and explore additional tools, hence the investigation into grid services tariffs. And we also have to think about prioritization schemes. Which comes first, the local reliability issue or need versus the need in the wholesale market? We have these dynamics that we're seeing with aggregators trying to figure out how to prioritize and respond to both wholesale market needs and distribution level needs, the grey areas are there and we're still working through those.

I would think that for the smart home solution providers, that's really something to keep in mind about how flexible their solution then would be to accommodate either a wholesale market need or a distribution system need. And we see a wide range of behind-the-meter devices and capabilities. And so, the extent to which the providers understand which of the needs their particular system can address and/or allow their systems to interoperate with other systems, then that will overall facilitate the evolution and adoption of ours.

Kerber: Excellent, John, did you want to add something to this question about just that longer term vision, right, when there's deployment of all these resources. What does the utility look like in that longer-term view?

Powers: I think that the big trends that we're all talking about, it's worth backing up a little and look at what those really are. For the last 30 years, sensors have been getting cheaper and more capable. Networking has been getting both cheaper and more capable. And we've reached a point where the aggregation of millions of devices behind all the customers' meters is not only possible, but it's increasingly simple and it gets easier every year. So more than just tariffs, and I'm a big fan of pricing as an economist, any type of automated response to signals of grid conditions is now possible. So, Michael's right, we have to juggle the priority of grid conditions. Is it local, is it wholesale? But from behind the meter, there's one signal that comes in that says, now is a better time than later to use. Now is a better time than later to curtail. So, there's a big place for smart home vendors in this world because they have a great economic advantage. No one's buying their devices just for the balancing of the grid. So, what's happening is customers are buying devices for their own reasons, which, with no capital cost, can then be turned into grid balancing resources that can reap some benefits. So, I think that the role of smart home devices gets bigger every year as the price of communication and the necessary sensors comes down. So, I think that who controls what when, I think that's gonna shake itself out. The trick is to have standards that can communicate with these devices because they have a great capability to balance the needs of the grid.

Kerber: Tony, do you want to add to that?

Koch: I think part of the vision is, for example, as we get rich in PV, it's a midday peak. Typically, there isn't load in the midday. And moving, for example, morning residential loads, mainly water heating is a fairly benign load to shift. Moving from the morning into the midday to take advantage of the PV generation. And the same thing, the duck curve in California, which happens because PV goes away with the sun setting and the load is still there. Trying to move that evening load into the night when there's availability of energy, typically, the wind in the northwest at least, blows at night, and so forth. I think the solution at scale is a combination of both tariffs and home automation tools–because not all customers will be in that mode of home automation It will take tariffs, customer-owned equipment, and utility deployed equipment to get us to the volumes that we're going to need. I've heard a couple people mention that it will be a great challenge to get this work done. We need to consider how we will be stacking the benefits. For example, a water heater is owned and operated by the customer, but if we stack the needs, we say there are needs for the customer, there are needs for a local circuit, there are needs for a local distribution utility, and there's a wholesale market need. So, you have multiple parties involved. How do we share that benefit so that we get as much value out of that resource as possible? Lining up the priorities typically the customer comes first, and the grid and these various levels of grid manifestations come later. I think building that relationship is a brand-new thing. Where in the past, like John was saying, in the past 30 years, basically, utility said this is the way you're going do it. You connect to the grid and I'm the grid and behave as I say. We need to flip that upside down and say we need to educate customers that the grid is no longer a central system, and we need the flexible loads, we need to work hand in hand. But really, priority number one is to have the energy needs and the customer experience be number one. And the grid follows, but there's room for everyone to benefit, it's just the coordination aspect that's been a challenge.

Kerber: We've been on this question for a while, but do you have anything else that you have heard yet that you'd like to contribute?

Barone: I've heard most anything that could come to mind, except I do want to maybe reign the question back into your initial ask was, which as I recall was what does the distribution or system operator look like? Am I remembering that correctly? And that said, Michael really hit on a lot of the points I would have gotten into. So, I don't want to beat a dead horse. And John and Tony also made great points. But here's the thing, the way I look at a few abstracted a little bit, is that the role of the grid operator stays fundamentally the same. But this is my opinion. I mean, I don't think anybody has a sharp or refined vision of this. But I think that system operator, or grid operator or distribution operator, stays fundamental to his or her charter. But the tools at his or her disposal are going to be expansive relative to where we are today or where we have been.

The opportunities, both problems and opportunities, I think, initiated by distributed energy resources force a paradigm that the tools have to be more complex, the analytics have to be more complex. And I think, fundamentally, the knowledge base, the skill set of our system operators have to add a new dimension that maybe historically hasn't been as evident. But I wanted to also cite an interesting observation from Tony's point. And I think this point is really lost on a lot of folks. And that is that, increasingly, there's this entire sort of customer economic opportunity, right? That is divorced from the grid. And the paradigm shift that I'm seeing occur is rather than the company mandates here's what happens and here's what you have to do and this is just the way it is, we have to be a little bit more flexible. And in turn, we have to try to understand that the customer and the, and I think the third-party folks that work with customers, aggregators, if you will, are going to likely be prioritizing the driving economic opportunities that may or may not have anything to do with the grid for those customers.

And then, the grid operators, or the utilities themselves, or the wholesale markets, basically work with what's left. So almost a secondary opportunity in some respects. Now, for us, it's a little easier, because we're vertically integrated, we don't have a wholesale market. We're effectively, for all intents and purposes, creating one.

And then, secondarily, we'll have a distribution-level market, if you will. So, issues around prioritization in selecting or directing accordingly, it still occurs under one roof, effectively. I think that's gonna be more challenging. More mouths to feed in other markets where you have an ISO and distribution company, for example. But at the end of the day, bringing it back home, I think system operators are going to have more on their plate and still fundamentally tasked with keeping the grid operating reliably without violating any of its fundamental operating conditions. And that's gonna require more tools and more skills to get there.

Kerber: That's interesting, putting the customer first and then working with what's left, right? So maybe this isn't the right term, but picking up the crumbs, and then those add up to some substantial grid benefit. That's obviously a different approach or different philosophy, I think, than historically considered, so very interesting. If that is kind of where things are headed, then I agree that the refinement of that vision needs some additional thinking. What's the immediate challenge to that? If you know you're headed in this direction where you want to place the customer first, but you want to provide these incentives that are aligned with either the local, the wholesale, or customer position, what does a grid operator have to do today to kind of get in front, to start moving toward that long term? John, we can start with you.

Powers: The thing that most of the folks that I know are doing is doing pilots that get as deep into the customer side of the meter as they can. So, if we all think that in the future more loads will be treated as flexible than have been in the past, that means you need to practice flexing them, right? So, with all loads treated as though they were a light switch, which is to say the customer has ultimate control. You turn it on when you turn it on, you only turn it off when you want it dark in there. Those loads will always be inflexible, and not particularly subject to any form of control. But anything in heating and cooling, anything in water heating, anything in car charging, any of the big loads can be moved around by minutes or hours without affecting the comfort or convenience of the customer. And the trick is to start moving into more programs that integrate all the way from grid operations to the customer home. And there is no way to do it except to do it. To get ahead of where the market is going, you have to skate to where the puck is gonna be, not where it is now. You have to start looking at advanced pilots so that you can build your systems. What did Rich call it? You need both the tools and skills to integrate large numbers of these homes. So, you have to do it a few at a time to see how it works, and then roll it out from there.

Kerber: Tony what's your perspective on this question? What do we need to do today to get in front of the challenges?

Koch: To move into these large scales, mass quantities, you have to have a standard that has flexibility, that can play with different systems and so forth and also lower cost. So, for example in the water heater space, traditionally was a load control switch, typically proprietary, and a fairly expensive piece of equipment. Also, a physical challenge in the home, you have to wire it, permit, truck roll, etc. With the CTA-2045 standard, it's a customer installed modual. It's equivalent to a USB port in your computer. In the old days, those who remember, the IBM floppy disc, the Mac floppy disc, the special cards to communicate with your computer. Now the USB port, you plug a printer, plotter, whatever. That's what this port and that technology that I showed you is all about. And in any piece of equipment, so you could have a thermostat, and electric vehicle charger, a water heater, a pool pump, what have you, it's the same standard applying to different appliances. From a utility perspective, if I just buy one widget, my technology widget, I could plug in that same widget into different appliances and control those loads. Standardization allows flexibility for the different markets and for different vendors.

Kerber: We're gonna move on to the next question just to keep things moving. Is there agreement on the most cost-effective approaches for managing peak demand? Rich, do you have a view on this?

Barone: Well yes, I have a view that there is no agreement. And what's further complicated is that we're starting to see that managing peak demand is really not the only issue. Whereas kind of historically DR was the big enchilada; at this point, we're faced with not just managing peak demand, but managing that trough that's occurring in the middle of the day. Or the two troughs and the two peaks we've got on our system, right? So just wanted to offer some context– the ball has been moved to begin with. So, then you have the further challenge of figuring out what's the most cost-effective way to do it. Look, this is a fundamentally a market question. For us challenged with looking at the bulk system issues first, and then secondarily looking at distribution level concerns, it really muddies the waters. But even if you wanted to isolate and call it on the bulk system services first, we don't know what the most cost-effective solution is going to be.

I think there's, in the long run there is a lot of thought that some sort of dynamic pricing could be extremely cost effective. But there are a lot of building blocks that have to be put in place both on the customer side and the utility side to really truly enable that. So, there's got to be some sort of short- and mid-term solutions that occur. And where we're looking right now is on the one hand you can take programmatic or tariff-based approaches to this, which we have done historically. And we are with some of our DER programs. And then the other alternative that we're actively pursuing now is an aggregator, a system of systems sort of aggregator base model. That focuses certainly less on the devices and more on the services that those devices can deliver. And looking at multi-year contracts much like a power purchase agreement, but we'll be calling them, or are calling them, a grid service purchase agreement. And looking at that to see if that can deliver the economies of scale. Not just for that first term contract, but to then in turn at low incremental costs, leveraging those in place devices over long runs. So, there's no conclusion yet. But those are the different directions that we're pursuing and trying to assess based on empirical evidence, and EM&V, which one is the best path. Ultimately though, and I know you'll probably get to this a little bit more in a few minutes. Some sort of real time or dynamic pricing, provided if you've got the responsiveness enabled, could be the best solution, but that remains to be seen.

Kerber: Thank you Rich. Michael do you have a perspective on this?

Brown: Well, I do, I really like what Rich said. I would point to the fact that some people might argue the most cost-effective approach to managing peak demand is to focus on energy efficiency and not forget that in the equation. Certainly, as we're looking at all the exciting ways we can use active management, we don't want to lose sight of ensuring customers are as efficient as possible first; it remains a key goal. Then I would think the other thing we want to think about is, which peak demand are we managing? Is it the wholesale peak or is it a particular peak on a distribution feeder that we need to manage, perhaps as part of the Non-Wires Alternatives project? So, we have to keep in mind that there are different types of peaks or troughs, as Rich mentioned. And so there isn't a one size fits all solution. And I think we have to get comfortable relying upon a basket of tools, be they pricing in agreed services, tariffs, or direct load control to manage the various types of issues that we've got to deal with.

Kerber: Okay, well, Rich, to your point about pricing I want to kind of move into that mood, that area. So, there's a lot of different tariff approaches, whether it's demand charge component or time of use. You mentioned kind of a more real time or critical peak pricing, so there's a lot of different approaches to that. Are there tariff approaches or anything that you're seeing that maybe is best able to influence, or align the interests of these distributed energy resources with the grid operators? John, do you want to start us off with this?

Powers: Sure, I want to stress that the industry knows a lot about this already, especially when it comes to time-of-use pricing. The utilities have been running TOU rate pilots and programs for more than 30 years, and there's great evidence that they do, in fact, control peak. They both can reduce peak and induce load shifting. PLMA has been highlighting those kind of Utility programs since the beginning, since 1999. Ahmad Faruqui of the Brattle Group has compiled this list of, I think he was up to 140 pilots, did a great presentation, the conclusion of which is, it might be time to stop running pilots since we know what the answer is. One of his big findings is that home automation significantly increases both the amount shifted and the persistence of the effect of shifting. Meaning that if you're doing everything manually, you get tired of it and the effect of either load shifting, or peak shaving tends to degrade over time. Whereas with home automation, the effects are bigger, and more persistent. So, I think that when you combine pricing with automation, you get some of the best of both worlds. You don't have to deliver a direct load control signal that might inconvenience some customers. And you can let them program in what they're willing to accommodate in terms of shifting based on price.

Beyond that, the critical peak pricing programs have been successful as well, but they involve a lot more customer education. They involve a lot more, sort of a higher level of involvement on the customer's front. So that's always, I think, gonna be a market segment of customers rather than all customers participating. As Tony admonished us earlier, we need to put the customer first on this. Just because it sounds good to an economist to jack up the price by a factor of ten at some period of the day, that doesn't mean the customers will view that as a very customer centric approach. So, you might want to offer it, but I think defaulting people on to very extreme pricing programs is probably not a path to satisfaction.

Kerber: The first question from the audience is from Scott Huffy. He says, are utilities working to provide kind of real-time energy production data that's an actual format for consumers? Something like a weather report for energy.

In the discussion before we talked about how utilities want to understand what's happening on the grid. Well it sounds like this is maybe the industry asking for the same kind of information from the utilities, right. They can help you by providing some kind of actual information. Who would like to take that on?

Brown: Well, over the years at the PLMA conferences, we've seen a number of utilities that have indeed implemented and tried real time pricing pilots. So that's a version of sending a real time price. And so that activity is out there for sure. And just to go back to what John Powers was saying, the best tariff is the tariff that fits the risk profile of the customer and that works best for the customer. And real time pricing isn't for everyone, right? We've seen a range of estimates. Some say about 9 to 10% of customers may be willing to go on to a real-time price. Another, not real-time, but another area where utilities are starting to publish information, and maybe Rich could talk about this, are they're starting to publish maps that provide information to folks about which areas of the grid can accommodate higher levels of distributed energy resources. So, I think as we move into the future, we're gonna see more of this type of publishing information related to the distribution system in terms of what we call hosting capacity, the capacity of a distribution system to absorb new types of DER. And I think we will see more and more options publishing real time needs as we move forward.

Barone: I'll just chime in just a bit, and maybe tie off Michael's response, and John's previously. And I'll reference back to something I very quickly waived my hand over before with respect to real time pricing. All these things are interrelated. I mentioned before that I think a lot of stuff has to happen on both sides of the meter to allow for real time pricing. Part of what I was alluding to was what John referenced, right, which is home automation, intelligent systems. I'm starting to see a trend towards the aggregation of systems, at the individual residence connecting many, many devices and running optimization or co-optimization schemes for all that stuff. I also have observed and I am a firm believer that intermediaries are gonna do a lot of the heavy lifting for customers to be their proxy or their representative for their personal preferences and therefore unencumber customers with having to actively manage those decisions. I think evidence should probably support that that would get greater efficacy of those, but the third piece of this is, what this question gets at, more visibility outbound from the utility. I suspect that that's a natural outcome of all the efforts we were discussing earlier with, what is the operator look like in the future? What things have to change and so forth? There's a lot that has to be undertaken on, at least I can speak from our side, such that we would even have that information to make available.

There's a couple of pieces. Michael alluded to the hosting capacity maps. It's something we're undertaking now. But as the greater visibility you have, the greater the populations and censors, you have, for example, on your network, the better informed those pieces of information can be. When we get an advance metering infrastructure in place, we'll have more information to share. And the third interesting piece is better weather forecasting, right? People don't think about this that much. I think certain people do. But for us to really get a short- and mid- and long-term forecast, so that we could give look-aheads in terms of information with respect to our system, we'd better have a pretty firm understanding of what our wind and solar production is gonna look like, for example. So, there's a lot of pieces that still have to be put in place on the utility side to give us confidence in the information that we could in turn share, either for the purposes that drove that question by Scott, or for the development of some sort of real time pricing scenario. The third element– I'll conclude with this–is that you look at TOU and you look at these kinds of static periods, but as Mike eluded to, you don't have… there's not one quote unquote "peak". It could be by circuit and in our case, depending upon weather, it could be by day across our system, right? So, what we've taken on now is, as we engage our aggregators in our grid service purchase agreement, we said okay, we're gonna take the principles of a TOU rate but we're gonna convert it into a load shift service, and we're gonna call many hours ahead either load billed or an evening curtail or a combination thereof. That gives us in terms of the operators our flexibility to operate the system the way they need, because not every day do they necessarily need to build load in the day, and not every day do they need to necessarily curtail peak demand in the evening. So, trying to thread that needle is challenging. The greater the information, the more dynamic the information can be distributed and then the more dynamic solutions can look like for customers.

Kerber: Next question is from Audi Cabaza. Audi says there's a comment earlier about using residential devices that are already deployed in the home and which also be very capital efficient. He says, how can the utility industry pursue that opportunity when the device market is extremely fragmented? So, you have many manufacturers, many different interoperability standards, right? The challenge of fragmentation, if you look out at that device market, and then from the device manufacturers, they look into the utilities and they're seeing that same kind of fragmentation. Any solutions for that challenge? John, you want to start us off?

Powers: I'll say first and foremost, engage. That's what the interest group Rich and I, Matt from Aquanta run, is all about. We try and do this many-to-many matchup of the fragmented utility industry and the fragmented vendor industry. While we don't try and run a standards group, we definitely try to show which standards are gaining traction on both sides– either from utility side or from the smart phone vendor side–and try and push folks together. The more we have an easy way for a utility to communicate with many different types, and vendors, and devices, the more we have a vendor who's able to communicate and deliver services for many different utilities, the faster this market can mature. So, I think it's good that the industry has not catalyzed around one standard, because it's early days. You don't want to decide this is the only way we're ever going to communicate with all devices for all time. But I think that we're getting to the point where working with standards bodies is gonna help bring the market to greater scale and greater efficiency.

Kerber: Tony I know you've been you've mentioned CTA-2045. Do you have a perspective on this many to many, kind of bringing the fragmentation from both ends together?

Koch: I agree, the bottom line I want to say is to use an appropriately designed open standard so that it fits. For example, OpenADR is a machine-to-machine type standard, it works great for C&I large facilities where you have a server. Utility server talks to the commercial building server, industrial server, but that standard is not a good application to talk to a water heater. OpenADR has a lot of IT overhead, a lot of security, and it wasn't designed for that. So, that's part of the learning process–learning the right applicability of the standards and applying them in the right sectors, in the right context. I think a residential home management system is a great brain. Maybe we do an OpenADR command with that in the future if that's a smart device that can deal with these little loads downstream. It's a maturing process for sure.

Kerber: Any other perspectives on the challenges of bridging that fragmentation?

Barone: I'll try to keep it short because I know we're running up against the hour. We recognize that and the way we've tried to handle it so far is, with our single, we're using Siemans distributed energy management system as our DRMS,hopefully to scale to a DERMS' full functionality. We use that as our maestro, if you will, and then we leverage the system to systems approach. We don't want to get encumbered by all those different standards and protocols and proprietary communication structures. So, what we do is we create a unified interface between our system and any other third-party system that manages portfolios of assets. So, we kind of limit the damage, if you will. We can send very standard, have standard communications back and forth. And then those aggregators can control their populations of devices in whatever way works for them. Ultimately, we'd love for that all to be standardized but in the near term, that's the way in which we've tried to kind of disentangle that challenge.

Kerber: Excellent, well Rich, you're right, we are at the end of the hour. So, I want to thank all the speakers, to thank PLMA specifically for partnering with Parks Associates to deliver this great content. Thanks to the speakers. And I want to thank the audience for your participation and your questions. Good afternoon.

Presentation slides available at
www.peakload.org/index.php?option=com_jevents&task=icalrepeat.detail&evid=43

Distributed Energy Resource Management System Software Selection

Presented September 13 as a group discussion webcast with DER Integration Group

Moderator John Brown, Skipping Stone

Rich Barone, Hawaiian Electric

Jim Musilek, North Carolina EMC

Derek Kirchner, DTE Energy

Lee Hall, Bonneville Power Administration

Paul Wassink, National Grid

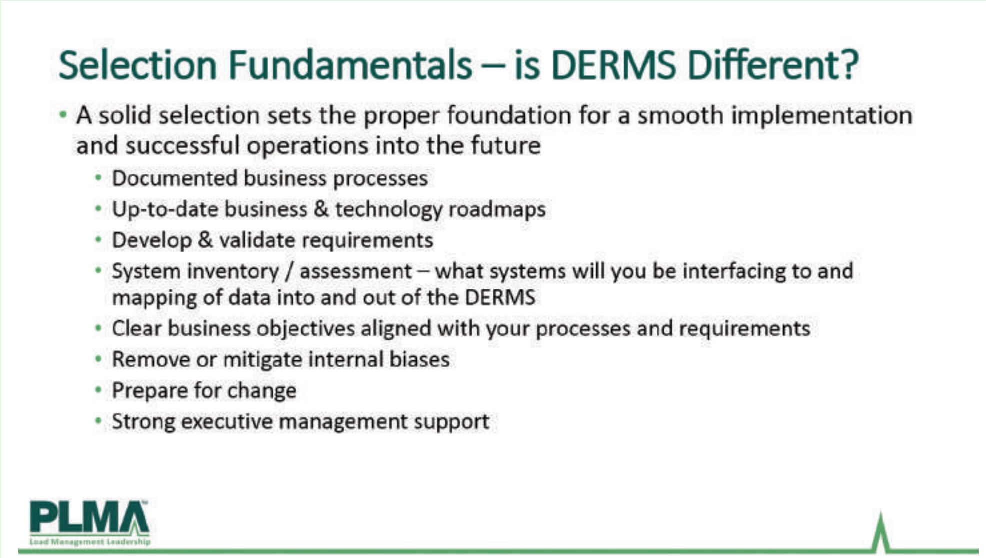
This Web discussion will bring together a panel of experts to share their experiences and best practices in selecting the right vendor and solution for a Distributed Energy Resource Management System DERMS. The growth and adoption of distributed energy resources (DER), renewables, microgrids, and other local energy resources is accelerating at an unprecedented rate. Energy companies are looking for more effective software solutions to help them manage this growth and to operate the grid to better take advantage of these devices. However, the software landscape is in flux with a myriad of solutions that each seem to have a differing view as to what really makes up a distributed energy resource management system (DERMS). You can shift the odds to your favor by adopting leading practices for software selection and laying a solid foundation for the selection through proper selection preparation.

John Brown: Good morning, good afternoon, and good evening–I'm John Brown and I'm a partner at Skipping Stone. Skipping Stone is an international energy management consulting firm. My personal background is heavily on the electric and gas planning and operations and commodity trading and logistics side, but throughout my career I've had a large focus on mid- to large-scale software selections, implementations, and optimizations in this space. That's been as a software vendor, as a consultant, as a systems integrator, and as the end-user putting in our own systems. In these roles, I've seen all aspects of the wonderful world of software selection and implementation.

I think these are really exciting times for the electric industry. We are seeing unprecedented growth and adoption of localized energy resources. This includes DER, solar, batteries, microgrids, etc. As a result of this, energy companies are looking for more effective software solutions to manage that growth and to operate the grid to better take advantage of all those devices. Now, if that's not enough of a challenge, the software landscape itself is also rapidly changing. Just a few years ago, most of us couldn't even spell DERMS, or distributed energy resource management system. Now it seems like every vendor and their brother offers some type of DERMS. It also seems like a lot of people have a different view of what a DERMS actually is, and what it should do. As a result, when you move into the realm of selecting software solutions, this makes it even more challenging and more difficult to compare solutions. We'll hear some good feedback from the panelists today on their experience navigating the selection waters. We'll even from one who had to implement multiple DERMS solutions to get at the functionality they really needed.

On top of this, the technology is rapidly evolving, the landscape's moving. How do you make sure that what you buy today isn't going to be obsolete in a few years? All of these factors complicate selecting and implementing a DERMs solution. And if you don't get it right from the beginning, the selection stage, it ends up costing a lot of time and money down the road. It can, or will, impact your implementation, and ultimately your operations. Let's review a couple things about software selection fundamentals. [Slide 4] These are really table stakes. This is the stuff you really just need to be doing, whether it's a DERMS or some other kind of software solution. I'm not going to go through all of them but let's look at the first two. One is, have you documented your business processes, so you have a really good understanding of what your processes are today, how you operate? This doesn't have to be a huge, complex document. You can keep it simple. Then you also want to have an up-to-date view of where your business' going, what's your technology stance and your technology road map. This will enable you to apply these to your selection criteria and will also drive your requirements.

When you buy software, it's very easy to just say well, I'm going to attend a bunch of demos and when I like what I see, I'll know it's the right thing. Doesn't work out too well. So, developing those requirements, validating the



SLIDE 4 View Slide at:
www.peakload.org/assets/images/DERMS-present-slide4.jpg

requirements is really a key step. And the only other thing I want to point out on this slide is down at the bottom, and that's prepare for change. When I was talking to the panelists, one thing that came up over and over again was they want to keep it simple for their operators. Part of that is making sure that you develop the training, the tools, the communication, everything to make sure that everybody's on the same page. Make sure people are up to speed, and that they have the tools they need to effectively integrate this new solution into their existing operations. Very important.

Let's introduce our panel for today. We have five great speakers from different places along the DERMS journey; people that are very early stage in the process, people that are in a selection, people that are implementing, and people that have implemented systems. It's a really good cross mix across different types of utility companies and even the companies themselves vary from IOUs to G&Ts to public power. Our first panelist is Jim Musilek who's the director of Grid Modernization at NCEMC. Jim, why don't you tell us just a little bit about you, your role, and where you are in the DERMS selection.

Jim Musilek: I've been at NCEMC for about 24 years now and working in the utility business for about 25 or so. During that time, I've had various roles in our power supply division with engineering, planning, operations, portfolio management and for the last several years I've been in our grid modernization group. Our current demand response management tool has been in place for over five years, and we're looking to upgrade it to accommodate new programs that are under development that will enable our coops to better manage load at the edge of the grid. We actually have an RFP that we put out in mid-summer, so it's very timely for us to be participating in this webinar. Thanks, John.

Paul Wassink: I'm Paul Wassink. I'm a Program Manager for demand response at National Grid. We have been running the demand response programs coming up on 3 summers now. We actually have two different DERM solutions, one for our commercial industrial program and another one for our residential program.

Rich Barone: I'm Rich Barone, Manager of demand response at Hawaiian Electric Company. So, I'm responsible for the demand response efforts here at Hawaiian Electric, Maui Electric, and Hawaiian Electric Light. We had a big sea change in mid-2014 when our commission told us that we needed to develop an integrated demand response portfolio which covered a full gamut of both capacity energy and ancillary services for DR. And, of course, as you all probably are aware, we have 100% RPS with a growing population of distributed PV and EVs on the horizon.

The task for us was to figure out a way to build out a portfolio of the future and all of the tools that go along with it to support it. Cornerstone to that at the time was our DRMS procurement in early 2015. We made selections later that year, and have gone through the regulatory process. And are finally now in the process of implementing what is now a decentralized energy management system as our form of DRMS moving into the future here, we should be going live in February of 2019, February 26th-ish of 2019.

Derek Kirchner: I'm Derek Kirchner from DTE Energy. I was formally the program manager and supervisor at the Demand Side Management Group at DTE Energy. In that role I was responsible for managing all DTE's demand response programs both on the customer side, on the residential side, commercial industrial side. We had started down the path of implementing a DERMS solution to start to set ourselves up for the future. Being from Michigan, we don't have quite the penetration of other utilities in the country of the rooftop units and distributed generation but we saw the writing on the wall that this is something we're gonna need in the future. And so, we went out and procured a solution and are bringing that in-house and developing it now so that it will be ready when the time comes.

Lee Hall: I'm Lee Hall who's the manager of DER at BPA. I'm happy to be part of this pretty distinguished panel. I've been at BPA for 15 years and 8 years in Smart Grid and Demand Response. Since we're a wholesale utility and we serve about 145 custom utilities, we call them preference customers. We have really been working on pilots and demonstration projects until and unless a resource plan says that we need that capacity or we have a non-wires alternative opportunity.

From that perspective, we've done the testing and done a lot of benchmarking. We've tested three different DERMS systems very successfully. The challenges we've had have been how to connect from a wholesale utilities standpoint through our custom utility to the end load. But we've been pretty successful with that since we now point toward a program where we do have a need for capacity. By the way, the need for capacity here is quite a bit different probably than other parts of the country because of our hydro capacity here and just the energy landscape in general, and another reason is lack of an organized market. We do point toward the need for DERMS in the future that will serve both our transmission and power parts of the company. So, it's the ease of use from the dispatcher's standpoint and also the cybersecurity concerns that we have. Thanks.

Brown: Let's jump into some questions here. First question, I'm going to let Rich start it off, "How would you define a DERMS solution and how would you differentiate from more traditional solutions?" Among people who submitted questions in advance, this was top of mind for them as well.

Barone: Thanks, you gave me an easy question to start with then, so that's good. I guess that is a tough question to answer, and what I'll try to do here is I'll answer it from the perspective of what we've done here at Hawaiian Electric. And I'll do my best, and I'm sure others are going to have different perspectives on this, but a couple of key elements from my perspective or our perspective for DRMS, for one thing, many hands make light work. So, we view our DERMS as a system of systems head end, and it really plays this sort of conductor, orchestrator, or maestro role for us. We don't have an organized market either here, so we're working on developing that in real time. Part of what we believe is integral to our model is allowing a number of intermediaries or aggregators play key roles from delivering the resources to the utility. In that respect, it is a system of systems maestro because it coordinates a lot of other maybe mini DERMS or secondary DERMS that had assisted as the aggregators. So, you've got, on the one hand, the integration aspect downstream, but we also have an integration upstream to our operators–both to our energy management system and our forthcoming advanced distribution management system. That's one key aspect, but from a core functionality perspective, we see the DERMS as an instrument that provides our operators and operating systems status, availability, and control of customer assets. In tandem with that, it plays a ton of back office functions. So, whether it be customer registration and enrollment, the abstraction of your programs to availability of grid services, if you will, to our operators is a key piece to this, to that point of making it simple.

It also handles settlement and certainly integration with our CIS to the degree that we do our own direct device control from our DERMS. The DERMS does forecasting for us, to the extent that we're integrating with third-party systems, our DERMS have to pull all of that forecasting and availability, put it together and present it upstream. And then finally, measurement-and-verification is another key component of the DERMS system. I wanted to then address your differentiation from some more conventional systems and of course future systems.

From the DRMS perspective, from all that back-office stuff, it's pretty similar to what you may have seen in the DRMS world in the past. First of all, key differentiation for us is we're not really taking a programmatic lens anymore, especially because we want to make these services available to our operators in the way that they would normally manage the system. So, our DERMS have to deal with a level of abstraction where it takes what's available, maybe from a programmatic perspective downstream, and presents it upstream as a grid service in a quantified grid service availability and dispatch for our operators.

The other piece to this that's different from some of the historical DRMS implementations is that we've organized this so that it can be topologically oriented across our networks, so that we can provide targeted and locational services to our operators and operating systems. In terms of the ADMS, I think we've seen a lot of conflation of ADMS products here that incorporate DERMS' functionality. I see a relatively stark differentiation, in that ADMS' are likely not going to handle all of that back-office stuff that I alluded to, also likely not going to handle a lot of the feedback looping and tracking of the availability of these devices. So, really, we see a DERMS and an ADMS as a services-oriented relationship.

The ADMS handles the SCADA, the OMS, and the DMS functions. The DERMS assets can be locationally targetable and available and integrated with an ADMS accordingly. But, that DERMS is really the thing that maintains the ongoing status availability and control for the ADMS. So, that's sort of some key differentiation. The other last piece I'll mention is that an ADMS or an EMS might be the right home for management of utility-owned DER. So, all I'm really alluding to in this case is the DERMS as we see it is the kind of orchestrator of customer-sided DERs. But the utility may have its own and those may be better managed through a combination of the ADMS and the EMS systems.

Brown: So how about somebody like Derek, from DTE's perspective, I know your rationale for putting it in as a little bit different than Rich's.

Kirchner: Yeah, I think Rich did such a good job of defining all the differences. In fact, probably the easiest thing I could do is over simplify it in a way. The simplest way for me think about this and the way we're viewing it is for the most part, and each instance can be different. I think of the DERMS doing a one- to-many dispatch where I need control of customer-sided assets or more distributed assets. Where an ADMS is more one-to-one type dispatch where an operator is looking at substations or voltage control or utility assets, and it's one-to-one. Then looking at the ADMS connecting to the DERMS, and the DERMS dispatching thermostats, or control units, or set points to get capacity. So, Rich did a much better and more elegant job than I did, but that's the way to oversimplify it, one-to-one versus kind of one-to-many.

Brown: Jim, as you mentioned, you've got an RFP out for a DERMS solution. You must have thought a lot about this in your selection.

Musilek: Yeah, for us, I'll echo what Richard has said already, and Derek. For us it's really essentially an evolution of our current DERMS. But the DERMS tool, instead of simply dispatching for demand response is really going to help manage resources at the edge of the grid. That's how we envision it, instead of just managing demand response, there may be some ancillary services it can provide.

We see our DERMS tool eventually becoming a tool that our distribution cooperatives can use to help manage their systems with more flexibility and transparency. I know the term distribution system operators is out there. We use the term distribution operator, but we're trying to position the co-ops to be distribution operators and the DERMS tool will enable that. In addition to SCADA and other traditional utility tools, this will be another tool to manage their distribution system. As more renewable resources come online in North Carolina the DERMS will be another tool to help integrate them. And there's the potential for sort of the consumer applications coming on. We want to give the co-ops a tool that will allow them to interact with their other distribution resources and help to manage loads.

Brown: Agreed, NCEMC has a unique situation with the co-ops and the number of stakeholders and systems. Paul or Lee, anything you guys want to add or cover?

Hall: This is Lee, I think again, Richard has done a really good job of giving an overview. But from our perspective, and this is a wholesaler perspective, is we're looking for a system that is simple as possible, quite honestly. With as few dispatch points, and actually drives the complexity of the calculations and even the M&V further down the supply chain, so to speak.

We also think the fewer parties to integrate the better, so the drive is toward simplicity, at least from a wholesale perspective, to make it easy for our operators to make decisions, and know what's available, and know that it's responded is really key. We've done our own testing, as I said, on some systems that we've had to operate outside the firewall. We've also done a lot of benchmarking, and the trends that we see are trending toward how to make it as simple as possible. And then, in our case, how can we, again, push the complexity to its aggregated dispatch point or to a utility dispatch point? Because we have, again, 145 utilities that we serve and whose load we would depend on. So those are just a couple of extra question marks from our perspective.

Brown: So, we've got a lot of agreement but some extra little pieces in there as well, so that's actually really good. Let's move on to the second question. And I'll tee this up for you, Paul–"What's your key motivation for selecting and implementing a DERMS solution?" What drove National Grid down this path?

Wassink: Our problem is a little bit easier than some other people on the call. We are a decoupled utility, so we have an ISO that handles all the really tough wholesale stuff. For our DERMS, we really needed something that will handle our DR programs, which really are just a peak load curtailing programs, although we hope to grow into other use cases in the future. So, for the commercial industrial side, that means we are looking for a DERMS that will automate a lot of activities such as customer registrations, load forecasting, triggering of DR events, and measurements and verifications. Whereas on the residential side we're looking for all that stuff as well as direct communication with OEMs, so that they can directly control devices such as thermostats, and batteries, and electric vehicles. However, we also need a one-touch solution for our grid operators. They didn't want to learn two systems, and I don't blame them for that. We only have about five events per year, so we had to tie in new systems to make sure it was a very easy one-screen operation for our grid operators with an air gap. Our DERMS solution never touches the ADMS. So, a person actually physically goes over to a dedicated laptop to call CR events.

Brown: Derek, what was the driver for DTE? It sounded like programs and related initiatives.

Kirchner: Yeah, I think it's a combination of kind of what Paul was discussing and then our kind of looking toward the future and wanting to get a little bit ahead of the curve. Again, in Michigan we have our own kind of constraints. We don't have the high penetration of rooftop solar, it's not quite Hawaii. However, the distribution and operations group that started on the path of looking at a new ADMS system. We had some conversations with them, and well, wouldn't it be nice if we had both, and they could work in conjunction together. Now we can kind of get it in and slowly grow and learn with it. Rather than getting a bunch of programs up and running then trying to put the control system back in on the top at the end. So, it's a much more future proofing for us.

Brown: Let's move over to Jim. I'll throw you a little curve ball here Jim. The first part is "What is the current and future envisioned state for the types of resources that are being managed to the DERMS?" We also received a number of questions in advance and have some on the chat right now about what people are doing to future proof their solution. Of course, Derek just mentioned a little bit about that but, Jim if you can speak to the original question and then anything you can add about future proofing.

Musilek: So, for NCEMC, the DERMS initially is going to manage some of our DR resources. So, customer-owned generation, thermostats, water heaters, and some curtailable loads. But we see more resources coming on, we see different types of resources integrating on the distribution system in the future. For example, we're starting to see electric vehicle growth in North Carolina, and of course EV chargers. We would definitely be interacting with those. Smaller inverter-based types of things for PV and batteries. We currently have a couple of microgrids that are relatively large that we interact with using our energy management system, but when our members start to develop microgrids, we're going to need something to interface with the microgrid controller that those microgrids will have in place. I don't see the DERMS tool taking over the microgrid, but it would be interfacing or interacting with the controller for that microgrid.

There will also probably be some type of interface at some level with distribution automation components. I think there may be, like what Paul was saying, there may be an air gap, at least from our point of view. But there would be some information or data that would be exchanged between systems. When you think about the Internet of Things, and the potential for all the devices that could be out on the distribution grid, that future suite of devices is only limited by your imagination. We see the future devices being on the distribution grid and there's things we probably haven't even thought about yet. I think it will eventually help support this notion of a transactive energy environment that could potentially develop.

Brown: Okay, now this stumped me when Paul said it as well, so I'll go a little off topic here. When you mentioned the air gap, what drives the air gap?

Musilek: Well for us, cyber security is a big issue and we take it very seriously. We're very concerned about that, we want to make sure that the utility side is protected from as much as it can be. And that would be one of the things that would drive us to have that air gap.

Brown: And Paul, is that the same on your side?

Wassink: Absolutely, our ADMS controls some very crucial things, and is a whole level of security above our DERMS solution. For customers to register for our DR programs and register their devices, our DERMs has to be exposed to the internet. Whereas it would be a large risk to connect our ADMS, which controls the grid, to the internet. So, those worlds can't really touch, and at least at the number of megawatts we have in our programs right now, they don't need to touch. I think we're gonna go quite a few years before there has to be a machine to machine communication.

Brown: Okay. And then, since I've got you, what about National Grid's thoughts around future proofing of your solutions? How did that factor into your selection or your thought process?

Wassink: : We definitely weighted it very heavily to what we need today, but 20% of our weighting was on future stuff, different devices that we hope will become cost effective in the future. We also have three-year contracts, so we're hoping the vendors we have will stay best in class forever, but if they don't, we're able to go a different way.

Brown: Rich, your company is in an implementation right now, what were your thoughts on future proofing?

Barone: Yeah, it was a big deal for us. In fact, during the process of our selection, we were put to work with a special adviser by our commission, just around our overall portfolio including the DERMS selection, and so future proofing was a big consideration. And there's really about three or four main elements. First of all, on the device side, I don't remember who was actually initially talking about the device selections or considerations, but we have very similar ones, right? EV's are coming in, we think, big numbers, deep distributed generation plus storage, behind-the-meter generation of all types. Of course, grid-interactive water heaters are a big asset class for us. General curtailable loads, but the micro group discussion was a really interesting one as well.

So, these are the types of current and future devices that we had to take in to consideration. And that really lends itself to the forward-looking future proofing. One piece of this is the abstraction. We took a services specific approach, which I alluded to earlier, which meant that we could be agnostic about the technologies that we were looking to integrate. If a technology can deliver a service in accordance with the service delivery requirements, then we don't really care what it is.

So, that became one means by which we could look to future proof. The other pieces have to do with how you standardize the communications, either with the third-party contributors or devices themselves. The locationality or the locational capabilities of our system was something that we knew at the time of procurement, we weren't ready for and wasn't needed, but we knew that it would be sort of within that five-year horizon, so we wanted to make sure that we stuck that out.

And then finally, somebody eluded earlier to transactive energy. Giving optionality to the market, working either directly with aggregators through the procurement mechanism, or maybe eventually through an auction type market, or retaining the option to do direct programmatic implementation downstream, were key parts to allowing a green field for the future evolution of a marketplace. So, those are the four main tenants really: the abstractions of services, locational capability, standardization of integration, and then market optionality.

Brown: Derek, you've talked a lot about DTE looking to the future. Do you have any specific things you did in terms of future proofing or are in the process of doing?

Kirchner: Not much more that I can add to that really comprehensive list of what we look for as well in making the selection. And I guess the only thing I'll add to that is we're talking about selection criteria and evaluation criteria. And that's part of it, but getting to know who you're gonna select and being able to work with them and have those up-front discussions that say, hey, we might not have this all figured out right now but here's where we want to go, and getting that roadmap from whoever the vendor might be that you're looking at as well. Where do they plan on going? I think some of the panelists, or most of the panelists will agree with me, I don't think everybody's got this quite figured out yet and it's evolving over time so those discussions with the vendors are just as important as your internal business case.

Brown: Yeah, I think that makes a lot of sense. You have to really have a good relationship with your vendor, build that relationship if you don't have it already, but have a good relationship with them. They also should have a product road map. Of course, road maps change for all of us, but they should be taking that path. I do think that having that trust between your company and the vendor is critical. I say trust, but also having that relationship in both directions. The vendor has good relationships with the implementers, and the implementers with the vendor, I think it's really, really important, you really have to trust them, because there is a lot that's unknown and moving, and so it makes it difficult.

We'll now turn it over to Lee in terms of requirements gathering. I know BPA is in a unique situation. You've had a great opportunity to benchmark multiple systems and to work with a number of top tier people in the industry. From your perspective, what do you look at from the requirements gathering side?

Hall: You mentioned the benchmarking. We have learned a lot from our own experience in pilots and demonstrations, but we've really learned a heck of a lot from our benchmarking. We call benchmarking finding out best practice. We travel across the country through TVA into Southern California Edison and really far and wide. And we invite people, we've put both the 2016 and 2017 benchmarking studies on the PLMA website and we're gonna publish one for 2018 as well. We derived some lessons from that, which, some of the lessons we learned are that utilities are making decisions to switch out their systems, and to scrap earlier versions, and to, in some cases, helping vendors and developing that relationship to take what the vendors have set on the roadmap and to really move it up in the development cycle to say we need this now.

The two basic–and this may be too basic– but the two basic things we ask are: who is going to use it and what type of resources is it going to be triggering? And again, you've heard me talk about the simplicity. We've heard from some utilities that they're also considering the trading floor function, and we call it the trading floor or trading function whether you're in MISO or CalISO or PJM. How can you use it not just for individual utility capacity or peak load issue, or reliability issue, but how can we use this on the market? So that's another requirement sometimes that goes into the mix. I'd like to also mention that OpenADR, we haven't talked about that, I don't think, very much on this call yet. We've found that it has flexibility, but it's just not plug-and-play, and each vendor integration requires a mini-integration project.

The general comment I want to make about integration, is that when you have two systems that need to talk to each other, let's say your parent DERMS system, that needs to talk to the aggregators; system, or other individual utilities, Integration is key. Sometimes it takes about half the effort in the entire project– that's pretty true of any software project. But integration is key–and we can't short sell that. Those are the things that we've done a lot of benchmarking around based on personal experience. We continue to read and try to understand where the industry trends are going. And again, the trends that we've seen is that no one system–and we may get arguments from our friends in industry about this–but no one system seems to cover everything that a utility might need so there must be some customization.

Brown: You bring up a good point on the integration side. Paul, your company is in production, I would expect that integration was a big part of your implementation as well, but am I correct on that?

Wassink: Absolutely, I totally agree. Like Lee said, you really want to emphasize that it costs a lot of money if you're just sending meter interval data over to a DERMS. In the utilities, everything has to be super secure, and so that takes a lot of time and money.

Brown: Yep, and also, Lee mentioned OpenADR. I know, Rich, on a previous call, we'd had a discussion a little bit about OpenADR, and it looks, as a standard, that seems to have a lot of momentum. Do you think that the answer? Or I know in previous conversation we'd had, people were also talking about APIs, which of course you'll have, as well.

Barone: Yeah, there's pieces to our solution for which OpenADR is the solve, but I think maybe no vendor has the full solution. I don't think any protocol has the full solution either. It's gonna be elements to the integration question that some of them can be fulfilled through OpenADR, and some of them we have other sort of standard approaches. So, I don't think there's a silver bullet here. Don't forget that in our model, on the one hand, we're integrating directly with aggregator head and systems downstream, and then, of course, operational systems upstream. Some of those standards, now we've got set and we're testing and that's great. We also have the opportunity and potential to communicate directly to customers for things that they're we're programmatically launching ourselves. So, our DERMS will also handle direct device level control. That's a very different question, especially as you're looking at a full gamut of devices, what protocols you may need. What ones have been adopted in bigger markets that you might have to employ as well? So, it's ever shifting sands on the integration front because we're dealing with a bi-directional integration as well or tri-directional actually.

Musilek: I just wanted to emphasize for the folks that have called in, how important the requirements gathering is. Because if you can't determine what you want, then you can't really ask the vendors to deliver it to your company. And it is a critical step in the process. We reached out to all of the stakeholders within our company from all of the business units that would interact with the system or use the data and we just tried to get input from them. Ideally, they would provide input on what was needed from a new system to improve their overall experience with the system. At the end of the day we wanted the key stakeholders to have ownership in the new system. We also talked to several of the vendors in the space and got a chance to see where they were heading and what their systems could do. We also participated in an EPRI DERMS working group. So, outlining those requirements, gathering it is very critical, and talking to as many people as possible is probably one of the best ways to help get all those requirements down.

Kirschner: I know I'm going to steal a little bit of the thunder from the next question, but that's okay because it's such an important point. Getting these requirements down is key and from a utility perspective I cannot stress this enough, finding all of the people you think you might contact with this and getting their input. You don't, sometimes you don't think about customer service issues or transmission folks or just billing; people that might not touch it everyday, they're not your operators, they're not dealing with the market, but somewhere down the line you might have the ability to help them with a solution or help them with the problem that they're looking for. And you can potentially do it with some of the work you're doing on the requirements gathering. So, cast a really wide net when you start to look at how you want to design the requirements in the system to try and address as many concerns as you can upfront. It goes down as a painful lesson learned, let's put it that way.

Barone: For everybody listening, I want to underscore that point in bold red. It's hugely important, especially because you're looking into a looking glass here, we're trying to look into the future for a system we don't yet quite have the realized use cases for, so by definition, you have to cast a wider net, have to get everybody's input. We were fortunate here, and I'd advise to the degree that this is possible for anybody about to undertake this initiative. We were fortunate in the sense that, actually I was specifically fortunate in the sense that I was not working at Hawaiian Electric at the outset of this project. I was actually working at Navigant, and at Navigant I also worked with Hawaiian Electric on its ADMS RFP development and requirements gathering in the months that preceded, at the time, with the DERMS RFP.

Why I bring that up is because helping to do requirements gathering and technical requirements and functional requirements development with these two systems somewhat in tandem with each other, to some extent helped to create a map for where the kind of dividing lines were and how the systems would be complementary to each other. I just wanted to feather that in because it turned out to be a very lucky thing at the time. But now, like Derek, I'm gonna kind of maybe breach into the next topic just a little bit, and that is this, that while all of this requirements gathering is absolutely essential, and you can't actually ask for a product until you've defined all of the requirements, as we've gotten into the implementation stage, I just want to point out that your job is not done there.

Because what I've been amazed by with working with the vendor for the last 12 months or so transitioning from those requirements that you've put out into your RFP in procurement into the actual development of the product, somebody else is alluding to the degree of customization, there's always gonna be custom development, but a vendor's interpretation of these requirements in kind of this high level response to an RFP can be quite different from what you actually had in mind. And when you're going to actually implement the product, there can be a lot of missteps and a lot of need to dive way deeper into the details to transform these requirements into a functional product.

Brown: I think that's a good point. It's interesting with the requirements. The more detail you can have on your requirements, the better it goes when you get into the implementation. It can be hard to do that up front sometimes, you can't spend your whole life refining and documenting your requirements, but certainly people tend to err on the other side which can be disastrous.

I would add on the requirement side just make sure that you're also including the data flow and integration mapping. Sometimes people overlook this or give it a little less attention. Where's the data going to flow? What data's coming in? Trace out, map out the data flows in the different directions and have a good part of that in your integration points since integration can be a really costly and time-consuming part of the process. Try to identify those and understand them as best you can as you move into the selection. Because when you implement, you're basically going to implement the things you've written down for your requirements. And new things will come up, but you want to minimize the amount of rethinking things you're doing as you're going through your implementation because that just slows things down. I've seen people get into a situation where they took years to implement systems like this because they keep changing their direction so to speak.

Hall: This is Lee, just a couple more points to add. Again, I've emphasized the integration piece a little bit earlier, and agree with the panel that it's key. A lot of what we're talking about is agile software development, but agile software development, in my humble opinion, can get a little out of hand and really start promoting and enabling scope creep, on the one hand, and therefore, cost overruns. I think it's also, my other thought is, it's also an opportunity to dig into business processes that exist at utilities and ask, are we doing the business process or is the use case in business process optimized so that we have a simpler system that we don't have to customize so much? So, there are opportunities to improve internal business processes that I'm quite frankly thinking about. So, we just don't carry on old business processes and have to cover and make sure we meet all those requirements internally, and just ask the question is there a way to streamline or somehow change or optimize those processes? So just another fabric, because the system will touch a lot of different parts of the company.

Brown: I also think you need to have an open mind in terms of changing some of your processes in general. It's an excellent opportunity to look and say "how are we doing, is this the best way we can do things or should we do things differently in the new world"? Sometimes the systems can drive this a bit, as in if you do it this way in the system it's going to be much easier. It's a careful road to travel.

Moving on to question six, this is for people who have implemented a solution. I'm going to start with Paul and the people who have implemented or are implementing a DERMS, "What surprises, good or bad, have you encountered?" On the live questions and also in the advance questions, we've had a couple of people express an interest in hearing things on the negative side of that. You may not have any of those, but, Paul, any lessons learned good or bad?

Wassink: I guess one slightly bad thing that happened to us. We were hoping on the onset to have one DERMS for both our C&I and residential programs. Unfortunately, we weren't able to find one vendor that we thought provided the best in class, the most cost-effective solution for those two different segments. We hope one day one vendor will do that. It would make it easier to run the programs. That was one big surprise for us. We were also surprised at the time and costs of system integration work between the utility platforms and the DERMS platforms. We were also surprised that not as many vendors as we thought use OpenADR. A lot of our curtailment service providers aren't using OpenADR and the OEMs don't really use OpenADR, they go through proprietary APIs. At the onset we thought everything would be OpenADR.

Brown: Other panelists, any surprises from your end? We've heard some sprinkled throughout the call, but others might have come to mind.

Kirchner: I don't have any major surprises other than to say, it's a utility IT project when it comes down to it. There's just the general conversation and surprises that come in on a daily basis as opposed to anything else. Outside of what we've talked about here, it still is an IT project and there's always going to be some unknown so just be prepared for it. Have a project plan, have a timeline, but just know something's probably gonna come up.

Barone: I have observations, I don't know if they're shocking. I mentioned the details before. This is the time where the devil in the details starts to come out and you have to really put a lot of elbow grease in. You also remember Derek mentioned before, and I followed up with that in terms of the requirements gathering, you need to cast a wide net. Well, once you get into the implementation that net has to remain wide. Not only are you integrating with a lot of systems internally–so you have a lot of internal folks to continue to coordinate with–but here's a really good tip we had gotten from our IT team and it's thus far proven to be beneficial–don't forget your users. You want this to be an operational tool leveraged by your operators. And you get into the throes of an IT project and you've got project plans to manage, and all of your middleware and integration work to do, and you have to manage the vendor. But at the end of the day you can't forget that the user acceptance testing is going to largely be done by your operators. I think the reality is and, again, this is counterfactual because we've actually taken the advice and engaged the operators.

Early engagement is far better than waiting until you are in that last couple of months of project, and then you spring it on your operators that they've got to now start to test the product, and they have absolutely no frame of reference, no sense of ownership, and no sense of obligation to be active participants. So, the lesson here that we've observed and taken full advantage of is hey, let's engage our operations folks early on in the process. Even if there's nothing for them to do now, give them a sense of ownership to buy in, have them incorporate into the refinement of the UX. So, when you get to UAT you don't have to have a big sales job at that time.

Musilek: I cannot agree more with Richard, I think that is key right there. And again, this is not a lesson learned, but hopefully a way to avoid or have only positive surprises, is really to over communicate. I mean, I think it's important to not be afraid to ask a lot of questions, so, you really understand exactly what you're getting throughout the whole process. So that's my two cents worth on that, but I completely agree with Richard on bringing those folks in early so they do have ownership.

Brown: I think that's an excellent, point. So yeah, the take away is having all the stakeholders involved, bring them in early. Then it's part of the whole change management of the project, getting them involved in there. One of the worst cases I ever saw was in the oil business, where an oil company was putting in a large system and the IT group put in the whole system. When they went to take it live the operators wouldn't use it, and they'd spent about $5 million US, but the operators revolted. That's an extreme case, but the more you can get those people involved, like Rich just said, even if there's not much for them to do, keeping that communication going, keeping them involved, and getting their input. I've seen a lot of surprising things come out of that and the sooner you get folks involved the better–that's great advice guys.

We have a couple of questions here, several questions, let's see if anybody's willing to answer some of these. This is really a cut and dry question, but a couple of people have asked about the criteria people used in selecting the system. I know, Paul, you mentioned 20% on the future functionality. But are any of the panelists willing to talk a little bit about your criteria for selecting a system, how you weighted items? It doesn't have to be exact numbers, but just the components or thought process.

Musilek: Since we're sort of in the middle of our RFP I can speak, we had a number of different criteria that we were weighting. Essentially, will the system achieve your goals? That's one main thing and is the vendor going to be a good partner? I mean, are they going to be able to collaborate with you to help grow the system, and develop it into the future? I think those are things that we're looking at for sure.

Barone: First of all, does it achieve your technical and functional capabilities? Second is pricing? Next, does it meet cybersecurity, information assurance needs? Do some test cases in the demo stage–does it respond to the data sets you pass along? That can really help sort out the vaporware.

Hall: Just a quick observation. Although we don't have an RFP, one of the things we were surprised about in our benchmark is how many companies–not a lot, but a few–are going to develop systems internally or in-house rather than going the RFP route.

But the question is about requirements and rating requirements are still very important. I think one of the things, at least for us when we go up with any software selection for any system is, what is the amount of customization that would be required as in contrast to getting the system simply off the shelf and having the minimal customization? So that's at least one thing that we consider.

Brown: I think that's a good point. We could go on for hours with the questions people have here and this panel is really great at answering and providing their point of view. But we have to wrap up so I want to thank Jim, Paul, Rich, Derek, Lee, all of you, I really appreciate your help on this and your great insights. And I know everyone else on the call does as well, so, thank you guys very much!

Presentation slides available at
www.peakload.org/group-discussion-derms-software-selection

DER Integration Challenges

Presented September 27 as a group discussion webcast with DER Integration Group


John Powers, Extensible Energy


Kelsey Horowitz, NREL


Rich Barone, Hawaiian Electric


Matt Carlson, Aquanta

This online discussion will explore how Distributed Energy Resources (DERs) pose unique opportunities and challenges for distribution system planners and operators, emerging technology teams, and program managers alike. Often lacking a common nomenclature, all parties struggle to understand and define the benefits delivered and costs imposed by the increasing assortment of DERs being deployed on both sides of the meter. This discussion will start with a framing discussion by Kelsey Horowitz of NREL, whose recent work includes development of a cost/benefit framework for PV integration into utility distribution systems. That introduction will be followed by perspectives from Interest Group participants who will identify some of the challenges, opportunities and forward-looking concepts on DER technology, communications and control, and customer engagement.

John Powers: I'm John Powers. My co-chairs are on here with me, Matt Carlson and Rich Barone. Matt is CEO of Aquanta. And Rich works with Hawaiian Electric. We have been organizing the upcoming DER integration group workshop before the PLMA meeting in Austin. As we were doing that, we came across a number of different DER integration issues that we wanted to sort of bring forward in the attention of the PLMA. In particular, while for several years PLMA has focused on the DER integration from a perspective of load shapes and effects that could be on the long end of the time domain in minutes and hours and days. We wanted to really coordinate with the groups who deal with short duration, integration, and in particular, the distribution system hardware integration issues that keep being raised when we talk about DER integration. That's something that PLMA haven't done a lot of in the past. So, We want to make that a key focus of this fall's conversation in Austin. In preparation for that, we've done a fair bit of research into what the state of the art is and we came across several bits of work from NREL.

We're pleased today to have with us Kelsey Horowitz from NREL. She has done work with her colleagues there in identifying distribution system cost associated with the deployments specifically a photovoltaic system. And she had a recent article in Renewable and Sustainable Energy Reviews that caught our eye and we're gonna talk with her about that. She's a techno economic analyst at NREL who researches focus primarily on the analysis of photovoltaic technologies with recent work focused on analyzing the cost to integrate distributed PV and other DERs into just distribution systems using both traditional and emerging solutions. She holds an MS in electrical engineering from Cal Tech, and a BS in electrical engineering from the University of Colorado at Boulder. Kelsey, we're excited about your paper. And if you could, could you just give us a little bit of an overview of how you came into this topic, and then take it as far as you want, and we'll start asking questions.

Kelsey Horowitz: I actually started looking at this topic for the Solar Office of the Department of Energy because they were really interested in understanding more of the potential impacts and costs of distributed PVs specifically on the grid. And then as we started to get deeper and deeper into this question, we realized that there's a very deep tie between what those costs might be and what those impacts might be to other DER and load control on distribution networks. So, we started to do some work looking into those issues now that kind of coupled power system modeling on real distribution systems that different utilities have throughout the United States with some of our technical economic analysis here. And then that paper kind of reviewed just what everyone knows about this so far. A lot of that comes from sort of inter connection reports right now, which is how this is typically sort of handled and practiced. I'm happy to answer questions about those areas that are the topics most pressing on people's minds.

Powers: I was particularly intrigued in your paper about the way you decided to break the cost of integration into sort of three parts, based on a combination of what we know and the level of penetration of renewables on a particular circuit or subsection of the grid. You called them if I recall hosting capacity, known cost, and fuzzy cost. There's sort of a continuum between how easy it is to integrate the DERs based on how many are already there. Would you talk about that a little bit?

Horowitz: There's a couple of pieces to this. There's kind of you mentioned these different categories or regions of cost and, below the hosting capacity by definition, you don't really have any. At least on the distribution level any cost associated with integrating those resources. And then, there's a lot of things that you can do sort of per system. If you are just making upgrades kinda reactively with specific systems that are interconnected, and then there's kinda these overall changes in the system where you're implementing an advanced distribution management system or a distributed energy resource management system or other kinds of modernization to the utility communication and control systems that have other benefits outside of just integrating DER systems. It's a little harder to allocate what's causing those, because they can also provide benefits in terms of reduced outage management, lower line losses, providing additional responsiveness for distributing energy resources, the bulk system potentially. So those are kind of the three different categories.

And then, to the point about control-ability when you already have existing DERMS system. I think a lot of this is really only an issue in places where really significant penetrations of distributed renewable energy resources have been deployed prior to some of the things that we know now about how they impact the grid. For example, In Hawaii, if you have a lot of inverters that have already been deployed, and can't provide some reactive power support, or ride through. Or in Germany we saw a little bit of this, where there were some bulk system stability impacts of having a significant number of inverter systems without the ability to have frequency or voltage right there. There can be some impacts there that are expensive to mitigate but if you're in an area where you really don't have a lot of these yet. Thinking a little bit more with a forward view of how you may be able to control those different resources and use the advanced inverter functionalities can really help sort of head off some of those costs and issues.

Powers: I've talked with one of your co-authors, Brian, several times now about the ability of inverters to mitigate some of the things that distribution engineers would otherwise, have to tackle on their own with new equipment or with new operating procedures on the utility side of the deployed DER's. And he's pretty emphatic that as you say, if the penetrations are low now, that's the time to enforce the smart deployment of smart inverters, because many inverters are smart and are deployed as though they're dumb. Is that still one of the things that you guys are seeing, or is there now better guidance for folks who are deploying these things in terms of what the utility should insist on when the DER's are deployed?

Horowitz: I would definitely agree with Brian on all those points. So, there are some inverters where they can provide some reactive power support, for example, that are installed. But there are a lot of them that are deployed dumb but they have the hardware and software capabilities to be smart, by and large. And so, I think it is really critical is your installing system to try to have adopt the IEEE 1547, the revised version of that standard, and use UL listed inverters that can also kind of enable some of these functionalities, so that you can use them. And then, there's these other policy interconnection issues around how you set up the agreement for how that inverter is behaving and I think that's something really interesting that we're starting to look at. So, we've seen pretty consistently and it's the exact amount of extra free hosting capacity you get varies by feeder and where the PV is but by and large having these advanced inverter functions has been really, really valuable for enabling low cost integration. And some modelling studies we've done and some actual field studies that have been done by others at NREL as well.

One thing that's really interesting, we're starting to look at now is that you could actually control not just the reactive power output but directly, the real power output of the system to help avoid some of these upgrades, and then potentially also provide some other services. And that's something that needs to be dealt with up front in terms of kind of structuring the interconnection agreements as well. Because it ends up getting kind of difficult to figure out how much curtailment could come from each system and what's sort of tolerable to the PV developers or the homeowners in order to not break the economics of the project for them and still encourage DER deployment. And so, there's some interesting questions around, they call them principles of access, but basically who gets curtailed when and by how much, that are set up in the interconnection agreement that are important to kind of start thinking about, too, if you're trying to implement some of those things. And there's a lot of work that's been done in the UK in particular around some of these issues, both at the bulk and distributive levels there might be so people can kind of learn from some of those good practices.

Powers: Could you for the benefit of simple country economists like myself and some of the other PLMA folks who are not as familiar with some of the IEEE standards. Could you just take a minute and talk about the importance of 1547 and its revisions lately? Because that's one of the questions we got, even before the webinar started.

Horowitz: The 1547 is sort of a family of standards that establishes the criteria for the capability of different DERs in terms of their performance, operation, testing, safety, and maintenance when they interconnect. So, it doesn't specify the settings that those devices have, but it's more about sort of their capability and functionality. And the original standard was introduced in 2003. And then in 2014, there was an amendment published to the standard that provided voltage ride-through, frequency ride-through, and active voltage response. Which has been deemed to be critical in kind of helping successfully integrate very high penetration of DER in regions that have experienced that kind of deployment. Like I had mentioned, Germany, as sort of a classic example of that. And then in April 2018, they just released a revised version of the standard, IEEE 1547-2018. And that basically makes additional changes from the original standard to help with the integration of DER. So, it allows for the provision of reactive power support. The initial phase of this is kind of mostly through like autonomous functions on the inverters, voltage and frequency ride-through requirements, some stipulations around bulk power systems' support, power quality, a couple other pieces. But the document actually got much more complicated. I think it went from like a 16-page original document to like a 250-page document for the update. But it includes a lot of specification for what the capabilities of the inverter should be that would enable some of these grid support functions in practice.

Powers: And just from my perspective on that is that the reason that's so important is that, without those capabilities, there's a much higher likelihood of expense and delay in integrating higher penetrations on a particular circuit. And the utility is alone in mitigating the voltage and other issues you just mentioned. But if the inverters are both built and deployed properly, a lot of those expenses go away, even as penetrations rise. Do I have that correct?

Horowitz: Yes, that's right. I mean, there may be at kinda low penetration levels that you don't really have to deal with this yet. But if not dealt with kind of upfront, later on, it will be much more difficult to incorporate resources at low cost if you don't have those functionalities available in retrofitting systems. Or even just revisiting interconnection agreements is much more expensive. And so, there's also this kinda like, even if you have like one system deployed in a particular area, and your overall penetration is really low, if the penetration grows, there's a lot of like locational aspects to being able to regulate voltage and frequency from DER in the grid. So, it may be that that first system that was deployed happens to be the one that can provide the most support from its inverter. But if it doesn't have that functionality, you have to kind of do it with these other systems. And it may be less efficient or you may have to curtail the output from those systems more and make the system owners a little more angry or something. So, I think it's real important to try to consider this up front, but it is a complex standard. So, a lot of information sharing like this or engagement with people who worked on the standard, I think, is helpful, as well.

Powers: So, when you talk about curtailment, you're talking about curtailing the output of the PV system, in most cases, or other DERs, possibly. And a lot of the time, in this group when we talk about curtailment, we talk about load curtailment as part of the strategy for integrating additional DERs at a longer time horizon, as sort of more of a load shape than an instantaneous voltage perspective. So, I just wanted to make sure that that vocabulary was clear to some of the other folks on here. But that sort of brings me to another, what I thought was a big contribution that this paper makes. Just in its definitions and what I call the taxonomy of all the different pieces of both, the integration challenges and the distribution upgrades that you were addressing. You really went very broad in this because when we all say distribution upgrades, we don't necessarily all know what that means. You did a pretty broad literature review and found pretty inconsistent definitions. And you and your co-authors, I just want to commend you for taking the time to try to standardize some of the terminology in this discussion. Can you talk about where the biggest integration challenges from the distribution system are in terms of what the biggest dollar impacts are and sort of where the main benefits can be identified?

Horowitz: In the United States, a lot of times there are voltage issues first that occur on feeders. And those can be sort of low- to mid-cost to mitigate with traditional upgrades. And then very low- to no-cost if you use advanced inverter functionality, at least to get up to some additional level of penetration of DER. The most expensive sort of per unit or per project upgrades tend to be around when there's thermal overloading on the lines or on the transformers and you have to replace those. Reconductoring or transformer replacement can be extremely expensive, a few million dollars. This can lead to project cancellations or just be very burdensome on projects, even if they can absorb the cost. And that's an area where having the ability to dynamically adjust the output from the DERs themselves or from the loads, I guess you can think of demand response as a DER, as well. But either load or generate flexibility in the load regeneration control can be really valuable for avoiding those kinds of upgrades. And one of the things that we found is really interesting is utilities typically plan very conservatively. So, if they see that there could be an overloading on the line for a snapshot, sort of worst-case scenario in time, they may upgrade the system. But in reality, and in operation, a lot of times, those kinds of violations are okay. And utilities don't even notice them sometimes until customers complain. And even kind of within the traditional set of electrical standards, these things can be kind of okay for a certain amount of time to have some kind of deviation outside of the range. So, if we can provide more information on the kind of time series behavior of these devices, and then have the ability to have some control of the load or generation on distribution. That can really help to avoid some of those expenses reconductoring or transformer replacements or something like that.

Powers: If I can just flip things based on your recent comment on where the big cost savings are. I know this wasn't the focus of this paper but we did a lot of work on solar sighting based on existing utility plans for system upgrades. Can you talk about the opportunities to defer already planned distribution upgrades from better sighting of DERs? Because certainly, some of the most, and you just pointed out, some of the most expensive, Upgrades are based on low growth or based on a need to fully retrofit a particular circuit. Have you found examples where deployment of DERs can, in what this group has been calling non- wires alternatives. Have you found that to be real? Are there opportunities for strategic citing of DERs to defer distribution upgrades?

Horowitz: We haven't worked directly on that as much in the project that I'm on. We have certainly seen circuits that are a little bit overloaded when there isn't any PV, which may be one of these areas that utilities would be identifying as potential opportunities for non-wire alternatives. And those can be alleviated up to some level of penetration with PV. I know there's a lot of other pilots that people are starting to implement around using storage as a non-wires alternative, or flexible load. And I think they have identified value of that certainly as an alternative in areas where they're accepting a lot of load growths that would otherwise require upgrades to their system. I think this is still early and a lot of that is still being borne out and it certainly depends on the specific type of DER. And if it's a load control, who's paying for it? And I think there's not quite as much information about the cost or marginal cost of demand response systems or something like that. But I mean, maybe you guys probably know a lot more about that than I do.

Powers: There's a fair bit of expertise on that throughout the audience here. And the PLMA just did a set of case studies around documented non-wires alternative implementations. But it strikes me that some of the methodology that you and your colleagues put forward would be super useful in the planning of new projects like that.

Horowitz: Yes, that's an area where I think the people on the call or with this group it could be interesting to keep collaborating now that we kind of have all these pieces in place to start being able to look at these questions from a few different angles. But there certainly are situations where the deferral value of DER is very real.

Powers: How do we get the distribution planners to let DERs provide the values that you are talking about? Because the distribution planner and distribution engineer world has been so divorced from this set of activities both in terms of organizational structure. And their own sort of training and best practices don't yet include some of the things you're talking about. Have you had a chance to think about the organizational challenges in getting the DER values recognized in distribution planning?

Horowitz: I think that is a great point and one of the biggest challenges around this. A huge part of these efforts is just going to have to be around basically engagement and coming to a consensus around how to do these things a little differently. Because we've run into, particularly when we are working with utilities, that they have a distribution planning department which you were talking about that kind of plans based on a certain set of conservative criteria, as I mentioned before. And that's their way of doing things. They'll build conservatively to make sure that nothing breaks. And the electric system does work really well in general now. And then there's the operations group that kind of manages things day to day. And that group is more important when you start talking about dynamic changes to load or generation output.

And then there's the interconnection group, which is often even sort of separate from both of those, although they do interact some with the distribution planning groups. That looks at individual interconnection applications for DER. And then studies them and tries to determine what kind of upgrades might be needed with the planning group to some extent. And so that organizational segmentation has been hard, and people have very different ways of sort of thinking about the world within each of those. I'm not sure they have an answer for the best way to do that besides just continuing to talk with everyone and kind of present data and research that shows what the impact of these things can be so that people can start to get more comfortable. And we've seen it's been really important to speak the language of the particular group that you're interacting with because they kind of care about very different things.

Powers: You talked earlier about the extensive standards process around 1547 and the sort of dramatic expansion of the last update to that. Were utility distribution planners and distribution engineers well represented in that process, and are they engaged in the specification of new capabilities for DERs?

Horowitz: I'm not sure if I'm the best person to talk that. I believe they were well represented, there were like two to three hundred people who were involved in the process of developing that standard and I know there was good representation for utilities there as well. And assuming themselves from the distribution planning groups were looped in on that. But I think there is public information on who all was involved in that process that I'd be happy to send to people.

Powers: I might throw it to Rich Barone for just a minute on this because Rich, you are our utility of the future representative here. You've been living in the cultural process that's bringing the different departments together at Hawaiian Electric to try to address these problems, somewhat under fire because the penetrations there have gotten so high. Do you have any comment on Kelsey's response to my question or do you have any other questions for Kelsey?

Rich Barone: I have several observations and affirmations, and a couple of questions which are gonna be hard to formulate but I'll do my best. I first want to thank Kelsey for your work and I think from our perspective here in Hawaii it's so pertinent. We are actively engaged right now with a multi-department efforts to start to tackle these issues from a service orientation, and what I mean by that is, Kelsey hit on a couple of very key, sort of what I'll call locational service needs, right? So, thermal overloading, huge one, and then voltage considerations. And the challenge that we're facing as we start to unpack this stuff is, and Kelsey I just want to try to understand how these dots connect, so this is sort of my first question. You talk about some of the advanced features that are kinda baked into some of the new inverters. And it is gonna have an impact potentially on the customers economic benefit for installing that system. Because ultimately if you're starting to muck around with the systems production, you're not gonna, especially if you get paid for export, or just the consumption of that energy for your home, you're not gonna make as much money. Your paybacks are gonna be longer. However, these conditions are very locationally specific, very dynamic and I would imagine very difficult to predict how often and how much they're gonna occur over the life of the inverter. Could you maybe dig into that a little bit and what you've seen so far with how those conversations have been going and how serious they are from either a customer or developer perspective?

Horowitz: Yes, that is an extremely good point. So, this is something we're in the midst of researching now and is a key piece of work that hasn't been published yet but we're working on for behind the scenes and trying to define a sort of robust framework for understanding different categories of uncertainty that could affect the real power output of DER's with some of these more advanced solutions. And so that we can conduct, sort of acceptably convincing assessments of curtailment. And not just us, but this is something that other people would be able to replicate in order to get some level of comfort with this more flexible type of interconnection of DER. That's definitely a challenge, and I mentioned some of the work in the UK that had been done before, and it's been a huge challenge there and there are a couple of different modes of sort of curtailment order and degree that they've seen are generally acceptable by stakeholders.

But they have different trade-offs in terms of the risk for the developers and the amount of other DER that can be incorporated without adversely impacting the grid. So, this is definitely an ongoing challenge, and I would love feedback from anyone on this call if they have thoughts about this on sort of how to do those kinds of risk assessments. But in the studies that have been previously done, there's been some modeling work on this for a few different sort of control regimes. And I think some of this was done I think with Hawaii and NREL. They're looking at volt var and volt watt sort of hybrid controls of inverters and have seen pretty minimal curtailment over the course of a year in modeling. I'm also happy to send this report out but it may not hugely impact project economics. So, it depends on the penetration level and it gets a little bit higher as you get into higher penetration levels. But maybe you can think of high penetration levels, maybe 5 to 10% with most of it being under 5% curtailment for a lot of the systems. Lower penetration levels, the curtailment, the real power curtailment can be, you know, even below a percent or a fraction of a percent for a lot of the systems. And so that's something that, I actually come from a background of looking at a lot more at the PV project economics. So that's something that could be acceptable in certain scenarios. And so, a lot of times what people have done In use of flexible interconnection for this kind of offer, okay, you can have this flexible interconnection and accept some risks. Here some range of risks you might expect. Or you can pay for the upgrades. And in some cases, maybe the upgrade cost is low enough that the developers don't feel like taking on that risk and they just pay for them. So, it's almost like a case by case kind of solution.

Barone: That's a great answer. I mean, it's obviously still in process. So, Follow up to that one is worth considering, if you look at ride through settings, and I don't want to talk over the audience's heads, but simply put, ride through allows the production to occur even if system frequency goes past a certain point. Normally, you'd have requirements where those systems would shut off at a certain frequency and then you'd have no production. So, the flip side to the point you were just discussing, on the curtailment side, you could leverage ride through settings to get increased production, sort of over an 8760 calendar, and furthermore, to the degree that you might offer voltage support. I'm not sure you can ratchet up production beyond the 100%. But I just wonder if any of those increased value opportunities tend to offset or nullify the losses through some of those other curtailments, or have you considered that at all?

Horowitz: I have not studied that, I don't know if, I guess I haven't seen any other research really documenting the relative benefit of voltage frequency from that perspective, but doesn't necessarily mean it's not there. It'd be really interesting to understand.

Powers: So, From my perspective as a former rate designer and as an economist, it just drives me crazy that our only form of compensating folks is based on a volumetric charge for something that the marginal cost is zero. And energy is very cheap and reliability is expensive. We should be compensating for increased reliability rather than relying exclusively on payment per kilowatt hour as the way we compensate these DERs. And if the DER can be configured to increase reliability (something that's expensive) we shouldn't be worried about foregoing a tiny bit of energy (something that's very cheap). And to me some of this is just baked into the economics of some of the deals that are out there rather than being strictly an engineering problem.

Horowitz: Yes, I totally agree with that. I think there's a big challenge in trying to define the metrics around reliability and resiliency that DER could provide value for. And I know there's some ongoing efforts with that. I would say, yeah, I definitely need lots of help from economists.

Barone: It's a little bit ancillary, or almost tangential to this discussion, but it's something that I've been mulling over, and I just wanted to get your thoughts. It's to some extent, to a large extent, and I think it's the crux of what you've been talking about if you look at advanced inverters and the settings and the sort of functional requirements or at least the capabilities of those and potentially the implementation of those as a rule of interconnection, these systems, at potentially some economic loss to customers, are going to be providing valuable services to the grid and be contributing to potentially offsetting or deferring or defraying costs. However, there's no explicit, in most cases that I've seen, compensation except for the fact that ease of interconnection, maybe kinda rapid interconnection, etc. However, what we'll be looking at in November and we, specifically as a utility, and the DER interest group and the industry generally, is what other stuff that sits behind the customer meter can be contributing to these locational and dynamic services and creating distinction. I'll just put it this way: any customer asset that is controllable, whether it's a supply type of asset, or a load asset, or a flex asset, that's sort of irrelevant. Some subsets those have the ability to be manipulated to effectively contribute to either thermal overloading mitigation or voltage regulation, and so forth. So, the interesting part that I'm struggling with is, in some respects, these PV customers that come in with advanced converters are forced to do it out of the gate and it's almost like a self-mitigating requirement. But yet if it's a service that a non-PV customer can contribute with a controllable asset, there's probably value to that service for which they can get paid. Have you encountered, in any of your work so far, where you might have this discrepancy and potentially market friction because some customers effectively could get paid for said services and others don't? It's just the rule of engagement. And there's good logic to it, I just don't know if you've stumbled across that issue at all.

Horowitz: Some customers, like PV customers, versus customers that could provide flexible load or something?

Powers: Yeah, so maybe I only have a power wall or a maybe I have a water heater, and I've got thermal storage. Or I've got another mechanism by which I can have a fast responding or dynamically responding device that contributes to voltage support or allows mitigation to thermal overloading. That may be a service that I'm paid for. But if it's PV and I'm using the advanced inverter, that's just a rule of kind of joining the party, right? So, there may be some economic discrepancies there.

Horowitz: Yeah, I think there are, and I think it's also just really variable, depending on where you are, it ends up being a lot of places don't really have the tariff structures and compensation mechanisms are really basic and traditional. And there's not really an opportunity for any of the resources to be compensated for this. And there is a lot of concern about both fairly sharing the cost and fairly compensating different resources. But I mean, in my opinion, that's still really under development. I think that there are other questions, I mean, besides the sort of market and tariff design questions around just tracking how much services people are providing and understanding how much curtailment is actually happening. Because I mean, there's questions around actual metering and data integrity and things like that that we've seen can be problematic on that end.

Powers: Yeah, absolutely, and we just got the question from another participant. How do you monetize services like voltage slash reactive power support? And the answer from a DER perspective, at least from a very lively disbursed DERs is that is absolutely open question. We don't have good metering and we don't have good pricing mechanisms for that, and in terms of highly distributed resources, I think you're exactly right on.

Barone: There's some logic to doing it as an availability. There can be logic applied to this, where you can make availability payments. And therefore, you're not necessarily bound by or relegated to tracking. The risk there is, if you don't track, you could exhaust that resource and get customer or resource fatigue. So, I guess I'm just underscoring the fact that it's certainly still an open issue that telemetry can help with I think, eventually.

Powers: While some of this sounds esoteric to those of us who don't do it every day, I'm sure a lot of the distribution engineers think we sound like freaks when we talk about all the program design, customer load shapes and all the other things that we obsess over every day. So, I think that the conversation between the PLMA practitioners and the distribution engineers is gonna be essential as time goes on.

Read the "Distribution System Costs Associated with the Deployment of Photovoltaic Systems" article at www.peakload.org/assets/resources/NREL%20PV%20Cost%20Paper%202018.pdf

Presentation slides available at www.peakload.org/group-discussion--der-integration-challenges

Reinventing Demand Response with DERs

As presented at 38th PLMA Conference in Austin, Texas on November 13, 2018

Moderator: Derek Kirchner, DTE Energy

Rich Barone, Hawaiian Electric

Troy Eichenberger, Tennessee Valley Authority

Brenda Chew, Smart Electric Power Alliance

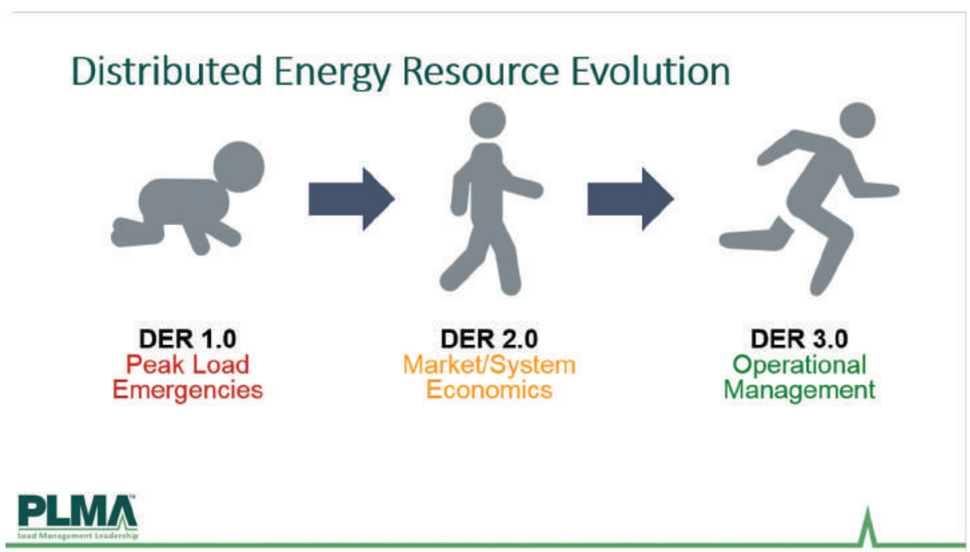
The industry today is bringing on more renewable and distributed energy resources. As technology advances and more renewable and distributed energy resources continue to come online, there are more options like EV chargers and interactive water heaters, as well as new market drivers to balance supply and demand on the grid to support reliability and capture operational efficiencies. Demand response practitioners are exploring the ability of demand response to fill valleys and clip peaks to respond to fluctuations and overgeneration along the grid.

Derek Kirchner: We are gonna kick off this panel on reinventing DERs, and f moving things along from the old traditional DR world. I'm the moderator for this panel, and the panelists each have a couple of slides each, and we're gonna do a little bit of background setting and discussion. We want to make this much more interactive than like a fireside chat, right? We are gonna have just a discussion and debate. We want you guys to answer and ask questions and debate with us on whether you think we are right, wrong, or crazy. It's fine, we can take it.

But the first thing we wanted to do is get the lay of the land. Where do you think this space is, whether you're a utility. A practitioner or a vendor? [Slide 2] Are we still in DER 1.0 where it's just when the system is hitting the fan and something needs to be curtailed? Are we in 2.0 where control is occurring for a market or a system economics? Or have we moved into 3.0 where DER's are controlled on an operational basis? The discussion with the panelists today will start to talk about where we're headed, which is this operational management. Using these resources 24/7. Using these resources 24/7 for whatever issue may come up, whether there's voltage or frequency or locational issues.

I'm gonna go through the bios for everyone quickly, and then we'll get to the slides. Brenda Chu from SEPA, she's the research analyst at the Smart Electric Power Alliance. She's managed SEPA's annual utility survey in market snapshot areas over the past two years. She leads a number of research efforts covering demand response, non-wares alternatives, and utility business models. Prior to joining SEPA, Brenda worked as a consultant, focusing on DERs, utility of the future, and grid modernization efforts.

My next panelist is Rich Barone. He is the director of the Demand Response department at Hawaiian Electric. He provides leadership and direction in DR strategy, business cases, technologies and program portfolio and market development. Rich works across process areas in the three Hawaiian Electric utilities to optimize DR and distributed energy resources to focus customer choice and system reliability while supporting the state's clean energy goals. Rich joined Hawaiian Electric with over 15 years of strategic planning early stage technology



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assessment, software development and system integration expertise.

And the final panelist is Troy Eichenberger. He's a senior program manager at Tennessee Valley Authority, has over 15 years of technical and management experience and energy efficiency and demand response program implementation. Mr. Eichenberger has a proven track record at delivering large-scale complex technical projects on schedule and within budget. After moving into the DR sector he's played a major in the implementation at TVA's Meter Data Management system. Further, he's managed conservation voltage regulation, dispatchable voltage regulation, direct volt control, and aggregated DR programs.

Brenda will start the discussion this morning and get us kicked off.

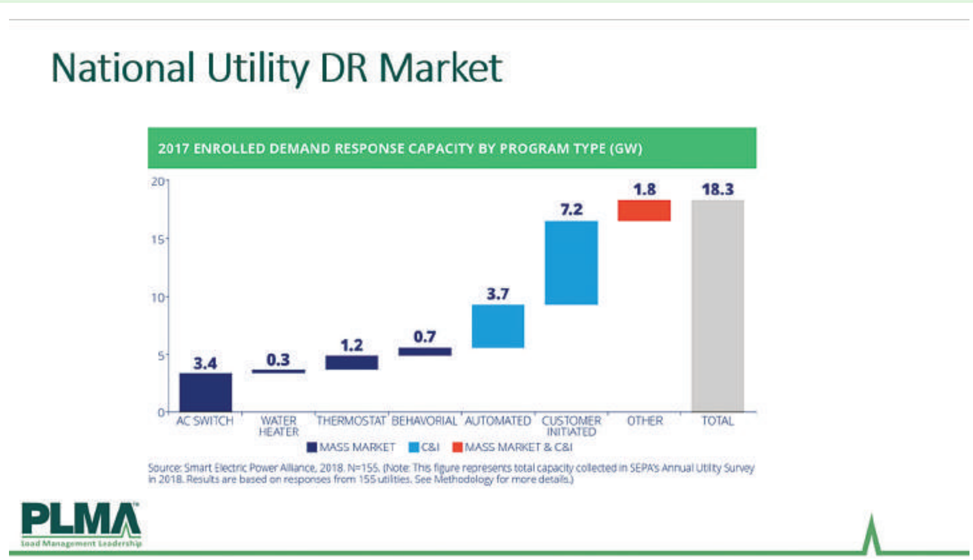
Brenda Chew: Thanks, Derek. As he mentioned, our Annual Utility Survey really sought out to expand coverage and represent utility demand response programs across the U.S. This year we covered about 155 utilities that represent nearly 89 and a half million customers. That's about 62% of customer accounts across the US. Derek really wanted me to try to give kind of background on where the market is today.

Our data collects information based off of the previous year, so our data shows how total reported DR capacity broke down based off of those 155 utilities. In aggregate, utilities reported about 18.3 gigawatts of total demand response enrolled capacity. [Slide 3] We really tried to break that down by customer market segment. In those navy blue bars on the left side, you can see the mass market programs broken down by AC switch, water heaters, thermostats, and behavioral programs. You can see that AC switch is still a large chunk of what's out there today when you're looking at it by capacity. Water heaters looks like a smaller piece of the pie at 0.3 gigawatts, and you also have increasing amounts of thermostats and behavioral demand response capacity. The light blue bars, which Troy probably can elaborate behind these numbers a little bit more is the commercial and industrial (C&I) sector. And customer initiated is a very significant portion, it's 7.2 gigawatts. We looked at Automated Demand Response which was at 3.7 gigawatts in 2017. Together this breakdown shows a picture of the market today. But there is a lot of different programs that are out there that you can't really ask for everything, cause I think the utilities will kill me if I expand that survey any further.

So anything else that didn't fall within those buckets, is rolled into the "other" category That could include some of the more traditional forms of demand response (such as agricultural programs, heat pumps, and pool pumps). And it can also include newer forms of DR such as ice thermal storage, electric storage being used as demand response, or EV managed charging.

I'll note that the numbers aren't everything, you can't see everything just by capacity. I wanted to juxtapose that information with the next breakdown where you can see how many utilities are actually stating that they have programs, and that's just utility program offerings by type. For AC switch, about 60 utilities stated having those programs and in aggregate representing a good chunk of DR enrolled capacity. In contrast, I just talked about water heaters sitting at 0.3 gigawatts in 2017. You think from those numbers that there are only a few utilities with those programs, but over 30 utilities say that they have those programs. This gives a bit more insight beyond what those capacity numbers are stating through that breakdown.

From a regional perspective, the U.S. demand response market really does vary by region depending on what's going on at your utility, what your customers are doing, and how much supply you have. Therefore from our data, we see a lot of variation of the enrolled demand response



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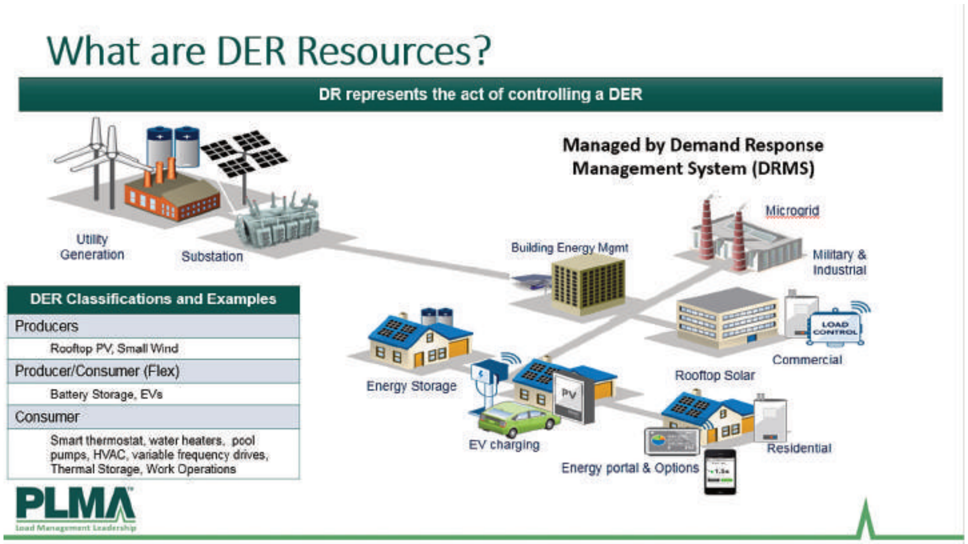

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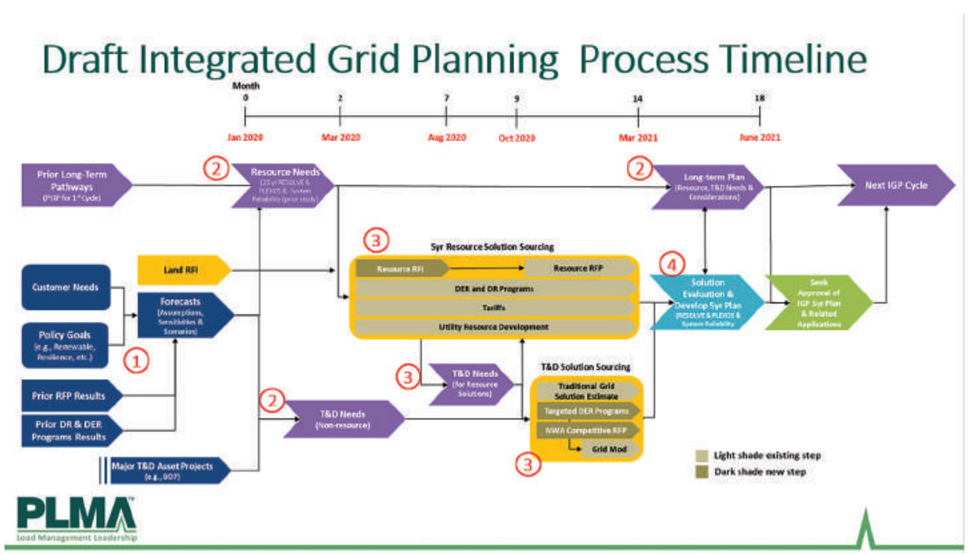
capacity by different states. There's a lot of DR activity taking place in California. In the Southeast there's a lot of C&I demand response stated there. Maryland has a significant amount of behavioral DR.

But in terms of where things are going, we do also ask utilities, what are you interested in? What are you looking at? And are you looking to help smooth out the fluctuations along the grid that come from renewable energy? Respondents are showing that over half are interested. A significant chunk is planning over close to 20 percent. And there are some early movers that are actually implementing DR in response to renewable energy fluctuations. There also are utilities that are looking at demand response, in terms of deploying it more locationally, and helping to avoid traditional infrastructure upgrades by using demand response.

Barone: I'm going pick up the thread here. I have two slides, [Slides 9 & 10] and I think they make some salient control as it used to be. And you can see that on this slide, I've categorized the three types of DERs. And that bottom tier, the load control type was really what DR used to be focused on. But the way that we're proceeding with our portfolio is, it really relies on the combinations of a full suite of distributive energy resources, from supply type resources to flex down to load and consumption type devices. And we're also noticing that focusing on specific technologies is starting to become untenable. Because increasingly we're seeing combinations of technologies that sit behind meters that all have to co-optimize with each other and there are inter-dependencies. I just wanted to portray on this slide that our universe of assets under the, quote unquote, demand response umbrella, has gotten significantly broader and much more. Using this slide for a specific point. And it links back to what I just talked about. We're right now, as a company, embarking on a pretty interesting and compelling process called IGP, or Integrated Grid Planning. Yes, I guess, maybe you've heard it all before as IRP and we had our Power Supply Improvement Plan a couple of years ago. But what's novel about this is that we've taken some of the principles we applied to our demand response portfolio and we're applying it to our entire resource plan.

And by that, I mean, we're taking, look we don't have a wholesale market. We don't have retail competition. But we're getting a lot of encouragement from our regulators to be more competitive with how we procure assets. And in fact, really divest or focus less as a utility on owning capital assets. So, this model takes into account what services does our system need through time based



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on forecast? And those services range from energy to capacity through ancillary services and then downstream to locational services. And so, the approach we're just now launching is to start with those services exploration and then embark upon a competitive procurement process for the fulfillment of these services. And this is particularly interesting with this crowd because we're not limiting that competitive procurement to your standard IPPs, but we're actually allowing aggregators, who roll up those distributed energy resources to respond to this competitive bid for the delivery of this full suite of services, in fact, bundling of services.

That's not the only way that we're gonna be activating customers with DERs for participating. There's really the three P's for this sourcing element for the customer side. There's procurement, which I just alluded to, and then there's pricing, and then there are programs. We'll still do some rate refinement. We're still gonna likely, I think, spackle in some shortfalls or gaps with programs. But it's apparent to me that the lion share of customer engagement is going to happen through intermediaries, through aggregators, through this competitive procurement process, which really puts this resource class on to sort of a par value with all other resources in our mix. And with that is a lot of responsibility. It's a lot of responsibility to make sure that it's firm, that it's reliable, that there's degrees of accountability. So, it's not a simple situation to solve, but we're kind of walking into the abyss.

We are going to, there's a secondary market offering. Once we've fulfilled our bulk system service needs, there will be a resultant set of needs on the T&D side, specifically the D side. So, we're going to have secondary offerings, especially in the non-wires alternative arena, but not exclusively that, right. We're gonna look at utility procurements and we're gonna look at NWA. We'll do cost comparisons, but we are gonna also open this up, this locational services procurement up to aggregated assets, locationally specific. So, this is an exciting time to take this resource that we're all talking about, and sort of bring it into the front and center in our resource mix of the future. So, I wanted to share that with you guys.

Troy Eichenberger: So, At the Tennessee Valley Authority, we are the nation's largest public power producer. And we serve parts of seven states, and we have our Energy Right Solutions group which is the bulk, the lion share of our distributed energy resources portfolio. And at TVA, our mission is to focus on energy, environment, and economic development. Likewise, in Energy Right Solutions, we have those same foci. With energy, we work with 154 local power companies and approximately 60 directly-served industrial customers to reduce system costs, improve reliability, and provide valuable services to our consumers. We work on environmental programs to provide clean, emission free resource alternative to traditional generation. And we also have a mission of promoting the economic development throughout the valley to bring good companies in, provide good jobs, make a better resource alternative to traditional generation. We also had a mission of promoting the economic development throughout the valley to bring good companies in, provide good jobs, make a better living for most. TVA and Energy Right Solutions have focused on a very systematic and simple platform of rolling out DER programs and Energy Right Solutions programs and demand response programs. We want to have scalable programs that we can ramp up really quickly if we need to, provide them for large customers, provide them for small customers. We want to make them simple and easy to understand.

We also want to make sure that the value is provided both to the company as well as to the individual consumers, and that there is shared value among all. In our Energy Rights Solutions Program, we have three areas of focus. We have demand response. It's approximately the size of our largest generating plants, so it can act as spinning reserves, should we need it. We also are endeavoring on electrification efforts. We were seeing the negative load growth recently, and realized that we needed to kind of shift direction a little bit, but do it smartly. Educate our customers on the benefits of electrification. Do it where there is a lot more engagement with individuals. And also we're shifting our focus from energy efficiency to electrification, but we're maintaining energy efficiency from an educational perspective. We have many programs for the local power companies that will go out and educate consumers to make TVA their trusted energy advisor to our local power companies and to our consumers.

Within the demand response portfolio, we have some traditional programs, but we're also investigating newer options as well. We have the bulk share of our demand response coming from interruptible power. It's a rate-based program working with our large directly served customers and a few of our local power companies to suspend a portion of their load on a 5- or 30-minute notice. We have seen that has proven to give us about 1,400 megawatts of load reduction. We also have two aggregated demand response programs in our Peak Power Partners group. And those programs are for C&I customers. The aggregated load for demand response, approximately 100 megawatts. And finally, we have our voltage optimization program which enables our local power companies to use distribution feeders to lower voltage on peak shaving events. And we've achieved approximately 150 megawatts of load reduction through those programs.

Kirchner: So now that you've heard from the panelist, does anybody want to change their mind on exactly where we are in this value stream right now? I think when Rich showed the map of kind of what's going on in Hawaii, I'd put you guys out as close to 3.0 as I think anyone that I know of. This is now going to be more the fireside chat portion of the show. Feel free to come up and ask questions. Please put us to the test with what you think about this stuff. As a start, I get to take advantage of this. So I'll ask the first question. How do we get to where DER's can become this trusted resource and to be valued against generation or other alternatives. How do we start to develop that infrastructure within the industry, within utilities, to get this technology on a level playing field? The tech works, what's the next step?

Barone: The tech that we're trying we don't know that the tech works. And more specifically, we don't know that the response is going to be what it needs to be in accordance with either the quantities or the delivery requirements. But the steps that we've taken that I've found to be really effective have been, first of all, broker meaningful and trust-based relationships with your system planning, with your T&D planning, with your generation planning, and with your system operators. Have them in the process, lockstep with you through the way. Have them develop a sense of ownership by working with you to define the requirements. Negotiate if you have to, if they're being too stringent with things, and find common ground. That has been foundational.

And then, in parallel with that, now this may be semantics, but in lieu of doing pilots, we've framed things where we've kind of dipped our toe in the water in the demonstration phase, or what we've even more cutely referred to as implementation phase one. Which isn't necessarily done to be cheeky. We are really implementing. We're dealing with smaller quantities. We're proving with living test cases the tech and the delivery requirements. And when you do that as a parallel effort with these same folks that you're actually rounding out the solution details with, and then they're riding along with you. When you do get to that 100-megawatt number, they're a lot less likely to discount that number based on what they've seen along the way. So, I think that's a little bit anecdotal, but those are the types of things we've done to, I think, engender thought with your system planning group or your enterprise planning groups. And making sure that they are with you along the process.

Eichenberger: Like you all, were engaging in an IRP as well. And it is critical that we are looking at all of the technology, all of the resources out there for demand response. And I think that with our programs, which tend to be more on the traditional side, they have been proven. And we have worked with the enterprise planning folks enough that they have full authority when we need it, they make the call, our power traders make the call, our balancing authority makes the call, our products produced. We've also done a whole series of metrics to determine the net gross ratio of our reductions. So, it's years of evolvement. Now, I will say the one thing that does concern me about DER in general is where you have different technologies coming into play like electric vehicles and whatnot. How is that going to focus on steel on the ground?

Kirchner: Brenda, from a national perspective, you've done a lot of research on the topic. You've surveyed utilities and solution providers. I think we all kinda feel we're on the precipice of this starting to take off, right? But who's going to be the first one or how are we going to get driven, dragged, or be the first guy through the door? Is this a customer facing and customer led initiative? Is it a regulatory initiative? Are utilities gonna take the first dance?. From your research, and having kind of national look at what's going on, who do you think's kinda leading this charge right now? And should they be? And if it's not them, who and how next?

Chew: I think that's totally regionally dependent, right? But I think that from a lot of research, there are a lot of cases where a regulatory mandate really did help push along change. Mandates like in California or Arizona saying utilities need to put in X amount of storage, or you need to meet these requirements, does help catalyze a lot of that movement and change. And I think that that's important too. But I think that that also is very dependent on what are the circumstances going on in that region. So Rich is in Hawaii, and you have some very different factors at play that are leading you to really try to figure out how to face those challenges. And rethink what is demand response and how that fits in, right? And then in California and Arizona, you're having this now overproduction of solar, and so now you're looking at DR very differently, perhaps to absorb excess solar.

It may potentially be up to the utility to really want to innovate more. But you're not having the same policy drivers and factors like in Hawaii and Arizona going on in your region pushing you to look at that. And so maybe

I'll punt that back over to you, Derek, and ask you if you think that: do you want the regulator to have to push you to do that? Or do you think that DTE is the one driving that change? Because I feel like that's kind of what we're talking about. When we're not looking at the top 20 innovators, what about the other 2,500+ utilities that I haven't captured that are in more similar conditions to you in Michigan, and don't have as much innovative activity to report?

Kirchner: Yeah, and I think from what I would call a more traditional IOU, right? That somebody that's maybe a little more protected investment, big market, not a huge penetration of customer sided DER. I think in the long run, there's certainly an opportunity for utility to get out there and kind of be the lead on this. Design the program right so it's cost effective to the utility, to the customer. There are benefits on both sides of the equation. But some of the struggle I think has historically been how do I, A, quantify those benefits so that everybody believes me? And then, B, how do I get in front of a commission that historically has been much more conservative that would go ahead and approve, right? We're in some proceedings now. There are some issues going on of trying to get pilot money. Whenever, maybe I should start calling it demonstration money instead of pilot money to start and do some of these things. But, how do you get that chicken and the egg conversation out of the way? Because a utility is not just gonna go out and make a multimillion-dollar investment with no recovery. But without the metrics to prove it, the regulator is not gonna give it to you.

Wendy Brummer, PG&E: This is a question for everybody. One of the coolest projects that we did at PG&E, which I think is really 3.0, but we haven't done anything with it. It was a little test and a few partners in the room participated. It was no humans to dispatch some of our load control switches. So, it was a hypothetical: here are some sensors and here are some systems. If criteria are met, then resources were dispatched in residential premises. I'm just wondering if this whole concept would be embraced.... considering that your operators aren't even involved with this. This is just sensors and automated reactions. Would something like this help to get to 3.0 and bring distribution operator confidence? Just curious what your thoughts are on that.

Eichenberger: That's a really progressive question for our company. I really like the concept, and I think it's something that we will evolve into. I think that there's still enough just authority that we want several folks looking at this before an event is called call, before something happens, and constantly monitoring the load. And if there is some unknown criterion that you might know about, a coal plant that might have some issues going on, that would not necessarily feed into the algorithm of your automatically executed demand response program. I think we can get there. I don't think we're there now. I think it would be great to have that technology, but I don't see it happening at least in the next two or three years at our company. But I think that it is something that would move us along, and we would be coming upright. And don't know if we'd be running at that point, but we might be walking.

Kirchner: We have this concept of continuous Improvement at the utility at DTE. And there's always our true north, right? That's where you want to get to. That's certainly I think the true north for the things that we want to do and the resources that we have. I think long-term that's where we'd love to get. It's gonna take some time.

Barone: The answer to your two questions is a yes and it depends. I think the first question is, does something like this help us get to 3.0? Yes, absolutely, unequivocally. The other question was, would this help operators' confidence? That's a very different question, rules in Hawaii state that they must have volt var volt watt functionality enabled. Well, that's an autonomous function that's based off of a curve that our operators are allowed to put onto these systems out of the box. And they're actually quite comfortable with that general technology. Conversely, we are pursuing a contingency reserve service that at least at present is driven by a set point detection at the device level. With a response, either from an injection or dispatch from a battery, or the immediate curtailment of hot water heater and the majority in our system, at 12 cycles or less. So, a fifth of the second, obviously too fast to have any human interaction, but that service on our system is extremely important for the stability. I think unlike a lot of systems, given ours, our frequency instability is increasingly a problem, right? Reliable response. So, they get very uncomfortable. They're happy that it can clear and we can bench test stuff. But now when you're promising to get 40 megawatts of that response out on their system when they've got 150 megawatts of total contingency reserve need. And they don't know precisely what they're gonna get, it makes them awfully uncomfortable. So, in that case, we've got to kind of build it up slowly under that risk threshold before we can prove to them that it works and then let us full throttle. But I think there is an inflection point where when you prove enough, the answer to that second question turns to a yes but I think it's a bit of a steep climb.

Brett Feldman, Navigant: Just to go back to what Derek was saying, I do feel like the technology is there. It's always gonna be improved and the cost can come down. But I feel like the policy and the regulatory environment doesn't keep up. And I'm not sure the customers are ready for it either. So, Do we need new business models from the utilities or from the vendors to take that next step?

Barone: I think you probably do need a new business model for the utility and it may go in one of two ways or not. But the two that I see are most obvious. One requires regulatory reform. I mean, something where they've got an open docket on Hawaii right now is PBR, performance-based regulation. I believe, as a near-term measure, that's essential to get here. I'm gonna speak narrowly within our DR department, as our contribution to the company's PBR considerations is a shared savings model. So, If we can demonstrate benefits realization from our portfolio and we can effectively ask for a certain apportionment of that effective savings back to the company. That's gonna offset the company's perception of losses of kind of the returns we can get on capital investments. And that's gonna be the only thing that can make a kind of a par value investment for the company. That's hugely important, and without that, I just see that it's gonna be a little bit of a hamster on a wheel. If you can have more devices and more aggregation of devices participatory in the system, and if you look at our integrated grid planning model of this competitive procurement, that seems directionally where it could go. Then I think the business model transformation is directly correlated to that new model. In what ways can you extract, if you will, revenues or a value from that model as the utility relative to the value that you're providing in terms of developing that platform? So, I do think that those two things may work as a sequential transformation over time.

Kirchner: Brenda and Rich just brought this up and it just dinged in my head. I know we only took a couple of pages from the DR snapshot and then survey you guys did, and I know you don't want to make it that much longer, but we're happy to fill it out. Transactive energy, I think that needs to be included going forward, and I know it's in its infancy kind of in this space. But did you get any feedback this year on the survey? I kinda ad hoc of somebody saying and raising their hand going, hey we're looking at this. Or is it still kind of down the road a little bit?

Chew: That's a great point, we hadn't really created room for people to really talk about that. But we're looking at what new trends do we need to be looking out for. And starting to monitor from different utilities as well.

And I definitely echo what Rich was saying, too. I think that from a regulatory standpoint maybe there needs to be reforms and changes that really make more room for utilities to take more risks and experiment more. Innovate. The way it's kind of set right now is kind of wise in that motion, so yeah.

Jon Bildner, Portland General Electric: I have a question for DTE and for Hawaiian Electric. If you can talk about the cost-effectiveness test that you use for your DR programs. And then talk about how you design programs, implement all these new technologies, without putting too much pressure on rates. Thank you.

Kirchner: The cost-effectiveness for us, at a very high level, is really trying to look at what's the levelized cost of capacity It's mostly residential AC load in the Summer season that causes my peak. So our cost-effectiveness takes a look at what's on the MISO market. What that capacity is clearing for in the auction what is set as CONE (cost of new entry) for building a new plant. If I can design a program with the benefits less than market or CONE, the commission takes a look at it. And say, okay, that's kind of the cost-effectiveness test. Levelized cost and capacity versus how else I could procure that in the marketplace. Now, that's changing a little bit. In the last two years we had new energy legislation come in 2016. That now requires us to go through an Integrated Resource Planning process and a Certificate of Necessity process. So it still was kind of the same benchmark, but it's now rolled into a holistic view of the utility rather than a one off process through a rate case.

Barone: We took two approaches in our portfolio filing to quantify the benefit of the portfolio. And since we were pursuing for grid services, we had to see if we could triangulate and calibrate to come up with a comparable value from each approach. The first approach was pretty conventional where we took the potential study work that we had worked on with Navigant. And we projected the availability of the services of that portfolio over a 15-year horizon. And then we really used those as augmentations to the production simulation models over that horizon. And so, you ran a model with it and a model without it, and you let the effectively production cost differential over that time period as a means of quantifying the savings which I've since been told is really hard to realize and we might as well not bother with accounting those.

So, in the same time we took a look at this value of services approach. So, we don't have a wholesale market, and our generators do lots of different things. So how the heck do does you value discrete services? So, we worked with another consulting firm, Black & Vetch, to figure out how can we create these fake assets, zero cost assets of different quantities that perform very specific services? And we plop those into the production resource mix, and we came up with an effective annual value of service for each of those discrete services over time. And we actually came to a pretty good alignment in the overall portfolio value when we looked at the value stacking relative to the value of services work. And we looked at the value relative to the avoided costs. So, we felt like, okay, we're not crazy. We had a pretty good order of magnitude to parallel. Since going forward with the programs, we were gonna procure through multiyear contracts with aggregators. But we knew nothing about what those prices were gonna be. What we did know is what has it cost us historically to run these programs, what have incentives looked like. And where we had some blanks, we went and got quotes. And we basically did a bottom up stacking of each of the services. And then we did some assumptions around how can you value stack by combining services and reduce some costs. So, we came up with a number of cost scenarios for the whole portfolio for 15 years. And we looked at that relative to the different benefit structures to come up with. And we did some sensitivities that we ran four benefit cost ratios for the portfolio, all of which were above one for all of our islands. So now it's a matter of, okay, using that as a benchmark, we need to go out and then procure these services through the aggregators. And we know the number we have to beat, and anything above that number is not worth contracting.

Steve Cowell, E4TheFuture: One thing that jumped out at me about this report is we're somewhere in the crawling stage in terms of moving beyond individual technologies getting a specific thing done to multiple technologies working together to address a multi-pronged, multi-issued strategy? This is now 30 years almost to the day that we made a deal with several utilities in New England about this concept of decoupling and performance-based rates. We've done recent studies, most consumers think you all just want to sell to your power to make money. That's all you want to do, right? So, utility business model reform, technology and silos. We talk about this program, we're gonna do solar here, we're gonna do demand response here. The silos, right? And the third, regulatory reform. Which one of these is the biggest barrier: changing consumer behavior, breaking down utility silos, or regulatory reform?

Barone: I want to comment. Not to be snarky at all, but while it's a great question, I think the importance of that question is it does highlight that there are three very large barriers and they're all really important. They're all problematic and, frankly, they all require effort to resolve. And I'd rather not, actually, distinguish between or among the three. But say, look, these are three distinct areas we need to work on.

Kirchner: I think that's a great point, because they're all interconnected. You're not gonna fix one and have the other two go away. They all three have to be addressed in very different ways than historically utilities have looked at addressing them. And that's really the challenge in trying to get down this evolution.

Jaden Crawford, Whisker Labs: It seems like there's something kind of underlying all three of those issues. And that is that when we're talking about customers or rate payers, I think in this context we're generally talking about residential consumers and their behavior and its impact on the system. Can any of those things really effectively be solved so long as the cost of that is not allocated to individual customers based on their use and/or abuse of the system? So, it seems like a natural incentive would be trying to not pay any more of those costs than one absolutely has to. But if those costs are just assigned to me as a customer group or a general location, I don't have a natural incentive. And it seems like it's hard for you to incentivize me in a way that I can really care about. So, Is it possible to really reform these things and as long as the costs aren't allocated to me as a customer based on how I'm using the system?

Chew: And I would also say that not just looking at the cost of the billing and the customers looking at that, there's also other aspects of recruitment and getting customers to participate in these programs. That has been a challenge from what I'm learning from talking to utilities and our research. Sometimes it's that you have a very diverse range of demographics. And there are some customers that just don't have that much load to be changing. And so you can't just look at that from a blanket perspective and think that the prices will just create the change that you're looking for on load. It's the socioeconomic factors as well that may be going on with those customers.

David Erickson, New Hampshire Electric Cooperative: I'm relatively new at the co-op and I basically came in with an agenda, I'll have to confess. My view was that the utility is undergoing radical transformation. The utility should push out DERs as an essential element of the total procurement portfolio. We need to start shifting towards a distributed, transactional control model, etc. The feedback I got was really interesting, which was basically it is NOT our job to do that. The view instead was that our job at the co-op is to provide a platform that enables our members to do whatever it is that THEY want to do. It's great if they want to do DERs, and we need to support that, but our primary responsibility is to provide electricity to them at the lowest possible cost and maintain safety and reliability. There is also an aversion to risk in terms of owning new types of supply resources, although that is somewhat being overcome. So, I wonder what you can tell me as an argument for either one approach or the other. I mean, is the utility just a platform, or are we actively pushing out a new generation, in a generic sense, of supply resources and controls that involve an integrated portfolio of demand side resources?

Kirchner: I think that has always kind of been the traditional utility model, right? We're a franchise monopoly because of the cost of the infrastructure that we put in, and that's why we operate and have the guaranteed rate of return and recovery that we do in a regulated system. That's the dynamic that's starting to change, and it's trying to determine the value of the grid and the value that a utility brings. And I remember in 2010 or 11 going to conferences and in three years we're all gonna be poles and wires companies because no one can survive owning generation any more. And that paradigm is now kind of flipped into well, utilities really still need to own their generation. But there's poles and wires businesses now where you can make money and have opportunity in supplying options for your customers to interconnect. So, I don't know if there's a solution necessarily or there's one right answer. But the value of the utility is starting to change from that traditional model into being that ability to have the grid and allow customers to connect.

Barone: I'll pile on that I think the answer is you can actually be both. And it depends on how you define platform. So, If you evolve the platform to be something that provides the types of opportunities and choice around the DER side of the question, then it may be in your interest. This is a little bit of a chicken and an egg thing, but you may say look, if we're gonna future proof and create extensibility by modifying and sort of changing, in certain degrees what our platform is, which has costs associated with it. So if you're gonna incur those costs, then you probably need to create the opportunity to take advantage of that modified platform to make up for the costs you've laid out, which may drive you to push more of the DER arena so that you can then have your customers take more advantage of the platform that you've now modified.

Eichenberger: I agree with that natural evolution of that happening as well.

Jeff Cook Coyle, Enel X: The whole human nature side of this to me is really interesting. The question of electricity and how people use it is really interesting in this discussion of the lights come on and nobody cares is one end. And then the other is like the Hawaii experience, well wait a minute, I can generate my own and suddenly you've got energy coming out of your ears and back on to the grid and everything like that. So, how do you manage that spectrum of the lights are on and nobody cares to, wow, I can do this, too.

Barone: You gotta figure out a way to allocate the costs. That's what it comes down to. I mean, you have to, we're in a tough spot. Even though we have one of the ends of the spectrum, we still have the other. And we've got to be able to build a system robust enough to support both ends of that spectrum. And that means more costs. It's gonna be more expensive. And how you allocate those costs is really I think the crux of the problem. I mean, I will say on the silo front, it starts with your senior leadership recognizing the need to matriculate and create a matrix organization. And then I find the effectiveness where we find it is because it cascades down to your middle management and below, and that's been helpful. And we're relatively small organization by utility standards. But your other question is assuming everybody can come together and sing from the same song book or hymn sheet. And we're gonna do this and we're gonna provide this platform for both the sort of uninterested except turn the switch on to hey I want everything behind my fence. Figuring out a way to allocate those costs. How can you achieve that platform at least cost–which is still costly– and then how do you spread them out in a fair way and that gets into the PBR discussion. It gets into new rate design or at the end state, same caveat, this is Rich Barron independent citizen speaking. If you were to transition to a transactive energy environment, you have different mechanisms to recover your fixed costs that maybe are frankly most fairly allocated to the most transactional of your customers. But that's aways off, and I think there are other means between now and then to recover these growing costs.

Kirchner: Well, please thank my panelists for being up here. Thank you for your questions and helping us out. I appreciate it.

Presentation slides available at
www.peakload.org/assets/38thConf/Reinventing-DR-with-DERs.pdf

Save or Shift? How to Successfully Transition from EE to DSM/DER

As presented at 38th PLMA Conference in Austin, Texas on November 13, 2018

Ray Martinez, Tucson Electric Power

Tom Hines, Tierra Resource Consultants, LLC

Balancing energy supply and demand is becoming more complex as more intermittent distributed resources are added to the grid. In this environment, DSM planners need to re-examine portfolios to determine how DER technologies fit with existing EE/DSM programs. It requires a granular planning process that considers the hourly load shape of each EE/DSM/DER technology to prioritize program opportunities based on alignment with resource needs. This session discusses an innovative approach to DSM/DER planning used to prepare Tucson Electric Power's 2019 DSM Plan. TEP created a resource-needs heat map and used technology-specific load shapes to rank all existing EE programs and potential new DER technologies according to their fit with the utility's marginal generation costs. This enabled TEP to propose a modernized portfolio that realigns existing programs and introduces new DER technologies using an objective method for determining whether to increase, decrease, maintain, modify, or eliminate each existing or potential program.

Teague Douglas, CLEAResult: Next we have Tom Hines and Ray Martinez talking to us about their approach to DSM and DER planning. Ray is in the emerging technology and innovations group at Tucson Electric Power. He is working on their mobility app strategy, behind the meter emerging technologies, customer engagement as well as the DSM portfolio. And he's joined by Tom Hines who's the principal and co-founder of Terra Resources Consulting with 27 years of demand side management planning implementation, and evaluation experience. He helps helping utilities optimize our DSM programs through integration of energy efficiency, demand response, energy storage, load shifting and other emerging DER opportunities. Let's welcome Tom and Ray.

Tom Hines: First of all, I wanted to note a quick change in our agenda. We had called our presentation originally Changing Perspectives From EE to DER. Actually, in the program it said, Shift to Save, How to Successfully Transition From EE to DSM/DER. Has anyone ever heard of regulatory lag? Raise your hand if you've heard of regulatory lag. So, At this point we were supposed to have filed this plan, and we're still waiting for commissioners to want to get ready to answer our 2018 plan. And so, we haven't filed our 2019 plan yet. So, we kind of changed it to changing perspective, because we're not sure how successful we're going to be just yet since we haven't filed the plan. But anyway…

Ray Martinez: I just wanted to add, we have a great hypotheses of where we think we were gonna go. And, hopefully, this change in perspective for the Arizona DER, DSM initiatives, it'll all come to play, hopefully, here pretty soon for 2019 planning.

Some of these DERs that we're looking at are some of the same product lines that are evolving from traditional volumetric energy efficient products that were in DSM. So now we're trying to see how these fit into more of the demand side management for load management purposes other than just polymetric systems so.

Hines: So, we came up with some guiding principles for the 2019 plan, right?

Martinez: Yes, so we wanted to look at the focus being on demand side management as a whole not just EE. So, for us and I know most of you is we still have this demand side management initiative where we have to be energy efficient and have energy efficient products that meet cost benefit. And that's still the path for us until 2020 right now. Unless that changes, that's what we're gonna do. We're gonna continue to deliver to that. Aligning the customer programs with the research planning needs is very important for us as well. And considering the customer value propositions and preferred technology use cases. Anything that we put out there… we as utilities know that in the past, we may not have been very customer centric. These customers are more engaged, the customer base is changing, and they're making purchases on Amazon, they're making purchases on Walmart.com, Target.com. They're paying for their Cox service or some sort of data package, Verizon, AT&T with the self-service interface mobile applications. So, We have to meet our customers where they are if we want to stay in the game. That's really important for us. The same thing with different product lines if it not be able to get them to engage. Maintaining EE offerings for limited income, schools and other special interest segments is really important for us, the utility, because most other, let's say consumer end products, aren't really looking at it. Although a lot of the manufacturers that are in here today have started to reach out and work heavier on that with us. And I think that's a value add where we're all shifting.

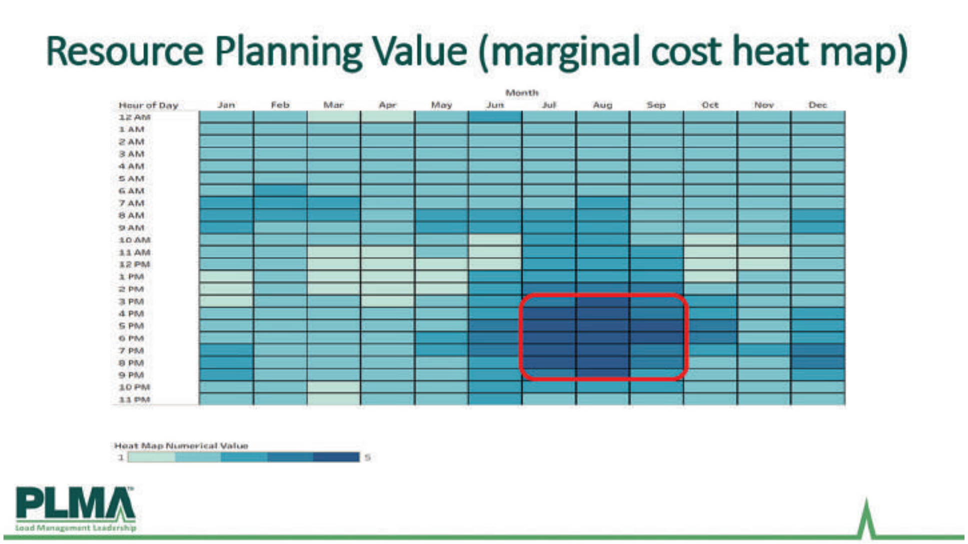
Understanding and developing strategic learning just to guide the future of the customer program offerings for us, in Arizona, is what comes after the 2020 savings goals? You know, what do we continue to do that's right for our customers and right for our business? We are an investor-owned utility in a regulated territory. So, we have different needs that we have to meet. But one is the customer. So, I think that's number one for us right now and for a lot of other utilities. Stay flexible. I always say this, I also lead the mobile application team for external facing mobile apps, and it's one of the things that we've shifted from is Agile. Agile development versus a waterfall development and a lot of things we go through in the process of development change and shift very fast. We have to be able to really meet that need quickly, instead of a traditional model where we've already post out the code and we'll wait for another update once a one year turn has passed. We're not doing that anymore. Just like your mobile applications are updating. Sometimes weekly depending on what happens. Whether security, whether it's a user interface, whether it's some sort of customer issue. We might not be able to do it as fast, but if we keep that same type of thought process will definitely move forward these DER technologies for our customers.

Hines: We started out with these guiding principles. To give a little background, in 2011 there was an energy efficiency standard passed in Arizona that was very kilowatt hour based. 24/7 kilowatt hours have the same value. And so, every kilowatt-hour-based energy efficiency standard, which I think for most of the utilities in Arizona had forced them, I think for the last several years, into a very focused, sort of myopic view of energy efficiency only. And with that commission order you saw from 2017, it's really kind of opened up the opportunity to do more in terms of a real integrated DSM approach. So, Ray and TEP called Tier Resource Consultants, my company, and asked how do we make sure that the programs that we're delivering as part of an EE or a DSM portfolio, make sense with TEP's changing resource needs? And so, the very first thing that we wanted to do was to look at each and every measure in the portfolio. Both existing current measures in the EE portfolio as well as new DER opportunities that we might be able to look at. And we wanted to do a full hourly, 8,760 hours in a year, a full hourly load shape analysis of all those measures.

Luckily, in the case of TEP, I can't see out there, but I think Debbie Lindeman there's in the back. And Debbie Lindeman, who has been working in the DSM field with TEP for many years, has a resource planning background. Debbie had foresight to start looking at load shapes quite a few years ago. And there's not many, at least in my experience did that. Many planned mostly only look at hourly load shapes of everything we were doing. And so, getting to that more granular analysis of your impacts really is a game changer, I think. And so just in terms of how utilities could go about taking from where you are today to where you might want to get with hourly load shapes. EPRI does have a lot of free regional load shapes that are available. Those are the load shapes that Debbie started with. So, build off of those, make sure that you're mapping those load shapes to what actual measures are in your portfolio. And when we talk about load shapes, I want to specify we're talking about savings load shapes, okay? A lot of people have end use load shapes for any different appliance. This is actually looking at a savings load shape of a DER, as compared to the baseline, okay? And we'll get into these a little bit more.

Martinez: And that was critical, I think having that strong foundation. Debbie, who works on the DS analysis team, is doing great work on this and had a lot of foundational work, as well as Jeff Yockey, who is in our resource planning. That gave us a solid start.

Hines: So, We set out to say how can we better align all of the load shapes that we're delivering with programs to TEP's resource needs? So, the next thing we did is we worked with Jeff Yockey, as Ray said. Jeff works in the resource planning group at TEP. And so, this is a heat map we developed that basically the lighter the color, the less valuable the resource is at that time. [Slide 5] So if you're thinking about energy savings, those light shaded areas are less valuable from an avoided cost perspective. So, this is just marginal cost. And then you'll see that area we circled, that really dark shaded area, is the area that has the most value in terms of resource. And so not surprisingly, this is pretty typical of a lot of utilities in the west these days. You'll see where this is kind of a very typical duck curve. Peak demand very focused in the summer months in the afternoon, mid to late afternoon, early evening. So that evening ramp three to 7 PM-ish, 3 to 8 PM. And then if you notice in the spring and fall, you'll see those midday chunks of energy really have very little value because there's too much solar on the system at that time. And we're actually seeing lots and lots of negative wholesale prices in Arizona for basically fall through spring. And so, in that, you don't have a lot of avoided cost value for those savings.



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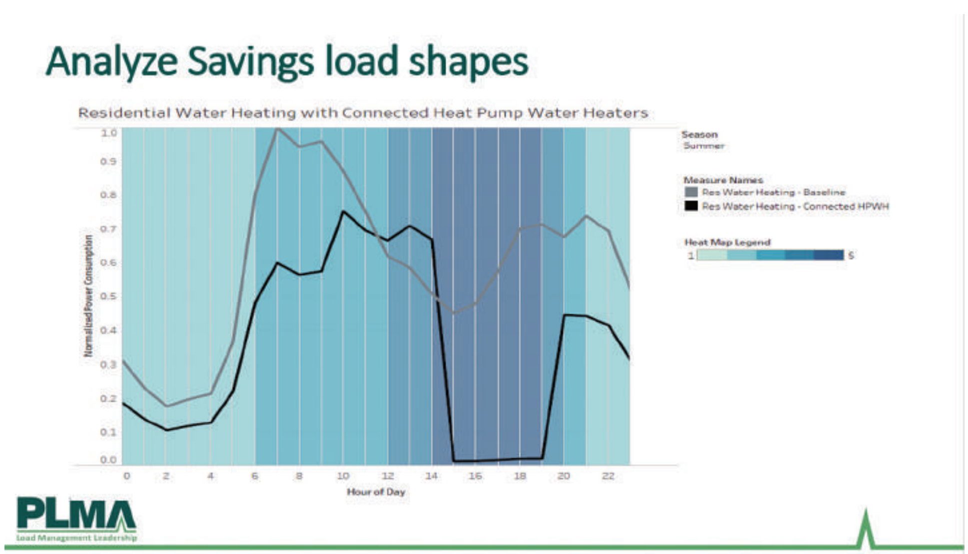
Martinez: Yeah, just to note that this right now the way you look at it right now it tends to be heat pump central air conditioning for us. And I think it's what we know right now, talking to different groups within our organization. It's like, what's to come? A lot of this stuff that we're doing, studies, aren't including a lot of the DERs that are going to come here in the near future, like electric vehicle charging. So those are things where we think this type of resource planning and these types of projections are gonna come in, or lease a marginal cost heat maps will really add value to us in the future as well. So, starting them right now in this DER interface into the DSM is step one. We started looking at how do we do this in the future as well.

Hines: And just to be clear with folks, we still did traditional benefit cost analysis of these. This is just a really effective way to show it, and I'll show you how we did it. And I think it helps with both internal and external stakeholders. This is a lot clearer than showing somebody net benefits on avoided cost calculations for benefit cost.

So, what you're seeing here [Slide 6] , first of all, across the background, you're seeing that heat map legend. So, This is those same hours of the day and hours of the year that we're now gonna plot different potential measures in the portfolio against. And you'll see as far as a savings load shape, what you see on those two lines. The light grey line is more of a conventional water heater. And then the darker black line is how a grid connected heat pump water heater might look. What we're able to do is start to play around with measures and say it's the same end use, but if I actually work with the customer to get a different technology installed, that still meets their water heating needs, it doesn't change the fact that I still want a hot shower and I still want cold beer and all that stuff, right? But if you look at this same measure in the winter, fall, and spring, you'll see that this provides a lot of belly filling, of load that we're bringing to the middle of the day. When we have so much solar, that this is helping us to actually absorb solar, integrate more solar on the system. And doing it in a way that is actually helping with our peak as well.



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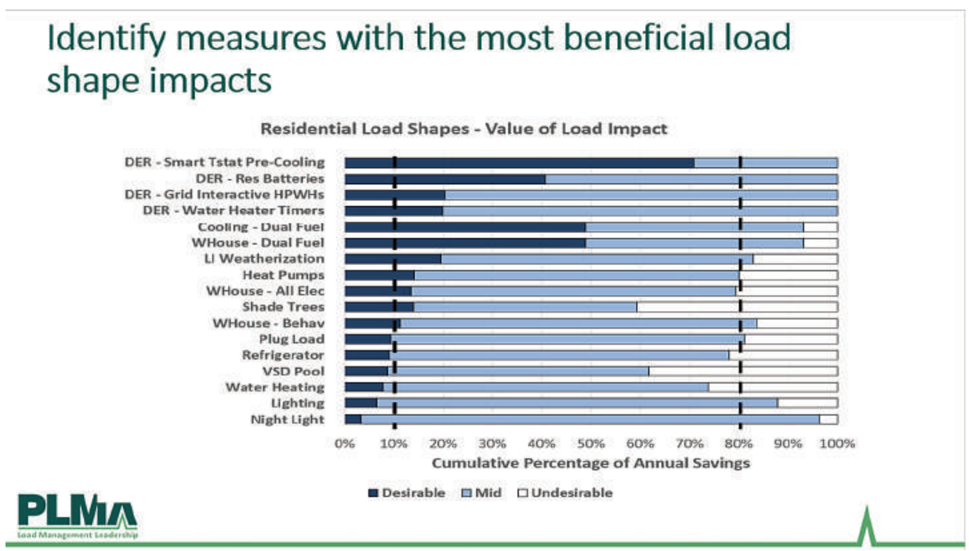
Martinez: For this specific DER, for our territory, those shoulder months, that's a different type of value. When we're looking at these DER technologies, it's not just what it's doing for maybe a demand response during hot seasons for a high load. But it's how is it gonna help us all, every hour throughout the year. And that's where the 8760s come in, and looking at these different technologies to complement each other.

I really want to stress this, for us, it's not the solution to solve the problem, it's to support us to get to that bigger picture. It's a lot of aggregate. I mean, we are doing different things at the generation level that continue to support our wrapping issues, but these add value differently. Could be in a pocket situation. It's just really talking to the different groups within the organization. I mean, resource buying, distribution planning. We'll get a little bit into more of that. Just wanted to just note that really quickly.

Hines: You need to meet the customer where they're going with what they want from their utility but maybe do it in a more creative way. This is the same end use. This is the same, ultimately, I'm getting the same value but I'm doing it in a way maybe is helping the utility. And helping the grid and helping to keep rates down for everybody over the long haul. Then what we did is again, try to envision those shades and background here are those same, we just brought that same heat map across. [Slide 7] So, you see where the darkest is the most desirable savings and the undesirable is in white in this chart, okay? We've kinda simplified it down to kinda three periods, desirable, in the middle, and undesirable. And then what we've done is you see those vertical lines; those vertical dashed lines represent 10% desirable. So, in other words, we looked at measures that produce at least 10% of their saving during our most desirable times. It will be good to have your measures at least helping you 10% of the time with the time that you need energy the most. You'll see where they are delivering a lot of savings in that kinda mid-time.



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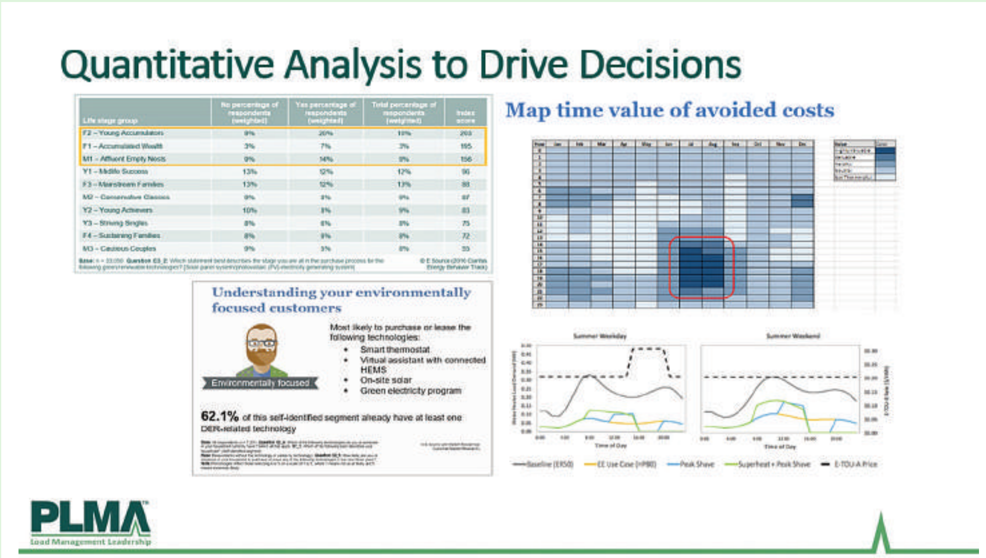
But the other thing we really need to look at hard in Arizona these days is savings during undesirable times. If you look at the savings profile for commercial lighting, it looks exactly like the production profile for distributed generation solar. Whoops, I'm saving energy at the exact same time that I'm producing an awful lot that's actually creating worse issues during my evening ramp. And so, what we tried to do in this is actually not just look at what we wanted. But reducing the savings that we don't need and that are actually causing higher prices on feeders and on different challenges for operations. And so, we also set that line at 20%, so if you look on the other side of that. Anything where those that white shaded is crossing that line, those are measures we really have to look at. Because 20% or more of the savings they generate are happening at times we don't need the resource.

My philosophy is, let's put the incentive money where we want it. So, our suggestion would be, maybe you take the rebates down on those kinds of measures. You still want them in your portfolio. But maybe some of the savings from those can go into some of the other DERs that you're thinking of introducing. Keep your budget about the same, but focus more on the things that are gonna drive your utility needs more.

Martinez: If you look at those, I would say those top value adds are smart thermostats. Which I believe everybody here is aware in one shape or form. Residential batteries, dependent on your territory, may add value. Also, like I said, look at these DERs as more than just one need. When we look at storage tends to be sold in the market as a resiliency. But there might be other values that your distribution planning group might have or your operations group might have from that resource. So grid interactive, something like advanced scheduling on different products that are high load, can be an added bonus or benefit. When you're heading from that DSM EE side of the road, to a more DSM DER or load manageable product line.

Hines: Again, this isn't necessarily about killing measures in a portfolio, it's about focusing our activities, and possibly changing measures in a portfolio. Smart thermostats being a great example. I want to show



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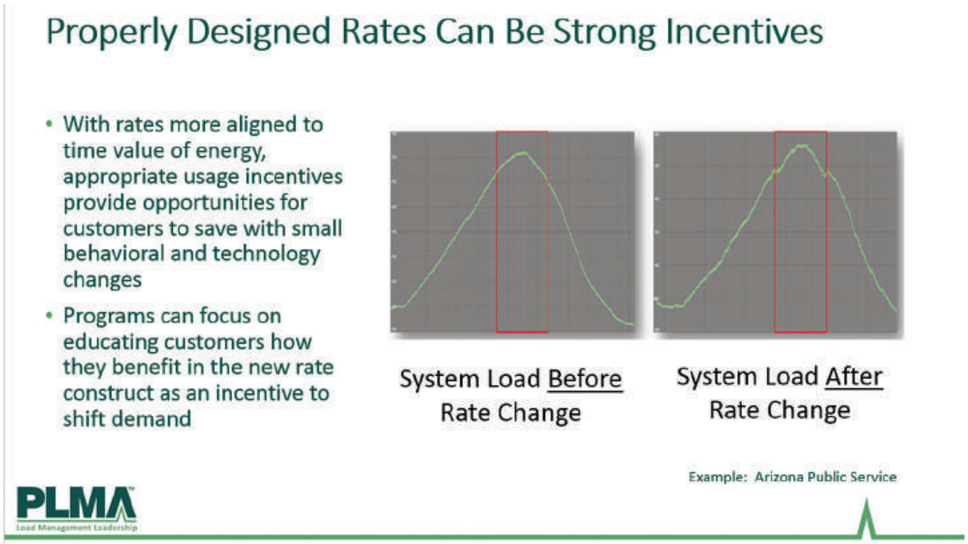
you a slide later that shows what happens, unintended consequences when you don't think about your EE smart thermostat program versus maybe more advanced rates if you're going in that direction. So again, what we showed you here was a slice of the resource look. But really what we like to do is take a quantitative approach to trying to drive your portfolio decisions based on one look could be at your resource needs. We can do the same thing, we've done the same heat maps with emissions. We want to talk a little bit about rates, and how we believe rates are a way that we can align customer interest and utility interest. But also, thinking about things like propensity and what do customer's want, right? Where are customers heading? Again, we've got to meet customers in the middle on this.

Martinez: And the different type of customers too. We talked a little bit earlier about someone may not want that or need that. Yeah, you're a certain type of customer, the different demographics really come into play. Where some customers might want more of a utility involvement, some of them might want less. So, understanding that propensity model is gonna become very important. Working with the different groups in the organization, just add a value, I think to the next level, with our corporate communications and marketing side. They try to understand customers on how they market to them. But we could take some of those same ideals and see how we can apply some of these different offerings to them as well.

Hines: I said we're gonna talk about TOU rates a little bit. TEP has a really nice TOU rate, as well as a demand rate for residential. In Arizona we are going there, and customers are following. Arizona Public Service that I do a lot of work with has 20% of all residential customers today are on a demand rate. The opted to be on a demand rate, they see great savings especially if we can make it convenient and easy for them with the right technologies. So, in the case of TEP, again, 3 to 7 PM, no shock. Did you guys remember that heat map, and remember how we saw that late afternoon in the summer kind of 3 to 7, 3 to 8 PM being the real valuable? Well there you go. [Slide 9] TEP's done a really nice job, I think, of aligning the rate message they're sending to customers with their resource needs, right? And so, because of that and because that's a four-hour window with opportunities for customers to be able to shift. And actually, as somebody who's done EE for 25 years or more, save a lot more, actually, in their TOU savings on their bills every month than most EE measures that I've ever dealt with. So, it's kind of exciting for customers.

Martinez: Yeah, and it's really funny too, I mean, when we look at that not utilizing the on-peak energy for customers, they have a big savings. I've talked to customers, it's up to $40. And they think like, well yeah, I'm not paying the utility. Every month. But for us it's like that's great. Don't use energy during that time because it costs us less to serve. And I think that's the value add. That's the win-win for the customer is they're saving, we want them to save, and then we save as well. So that's a big add, but really important is the rate design has to be right.

Hines: And I feel like this is an area we need to get more sophisticated with in the utility world and how DERs interact with these. So next slide is actually an example from Arizona Public Service Company. [Slide 11] So, as I told you, APS had a lot of customers transition to new rates over the last year. And so, these are just two system-wide APS load shapes from 2017 and 2018. They happen to be almost the same day, it was in June. Just to note, the one on the right is actually 2 to 300 megawatts lower, so that you can't see that on the scale. But what I wanted to point out that you can see, is you see how the load shape has actually changed, and we're seeing a shoulder right before the peak starts? And that is pre-cooling, right? That's customers understanding the rate signal and doing some pre-cooling. And then you see a 200- to 300-megawatt-hour reduction in the peak, and then after



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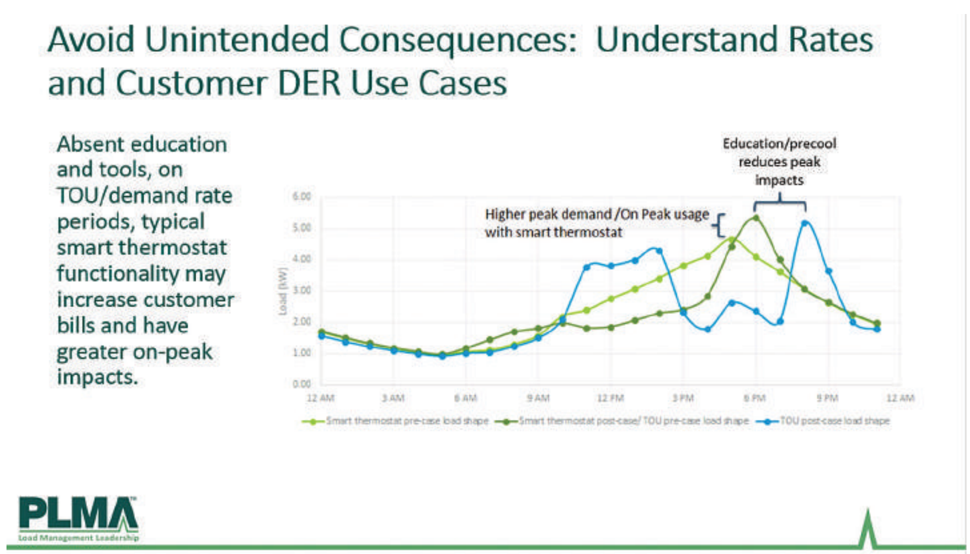
the peak you're also seeing a little bit of that snapback afterwards. So, this is customers responding and giving us demand response every day of the year. And doing it in a way that they can be comfortable with, sorry. But we have to be careful with that again, we've got a lot of EE programs out there. And so, we started looking at how do our EE measures and how the DERs interact with advanced rates.

And the answer is, not very well sometimes unless we're able to educate customers. And work with the industry, to create smarter smart thermostats that actually understand not only the weather outside and my occupancy, but the rate I'm on. And so, to just take you through this slide really quickly, the light green represents a what we call a pre-shape. [Slide 12] So that's a programmable thermostat, okay? Pretty typical HVAC usage for a summer day in Phoenix. Peaking in the late afternoon. The dark green that kind of olive, represents a smart thermostat in our EE Program that has not been optimized for our rate. And so, what does smart thermostats do? Everybody knows this, right. How do they save us a bunch of energy? Right, occupancy. And things like geo fencing. Okay so I'm away from home during the day, and so you see all those savings I got. See how that olive line is much lower during the mid-day period, and then you'll notice that because of that, I come home. My home is hotter and now my thermostat reacts, and so we need to think about that more.

Martinez: A I really like this graph here, because to Tom's point it's a lot of these products. If you see that customers were taking on the volumetric savings side of it, the energy efficiency. Because that's what we were doing with the demand side management portfolio offerings. Meeting that savings need, trying to meet the standards in our territory. So, we're doing everything right from energy efficiency perspective. But it works differently throughout the hours of the day.

Hines: And then you'll see that third thermostat, that is one that we have actually demand optimized. And so, that is pre-cooling before the peak period. And then, actually, because it's demand optimized, it's providing a small burst of cooling in the middle of that on peak period for 30 minutes. It's a one-hour demand period. And so, it gives the customer some comfort without hitting a new demand.

Martinez: This just goes back to really looking at it holistically when we're looking at the different products, DERs. [Slide 13] For us, we're long on generation throughout our territory. So, demand management, or demand response really doesn't make sense when you



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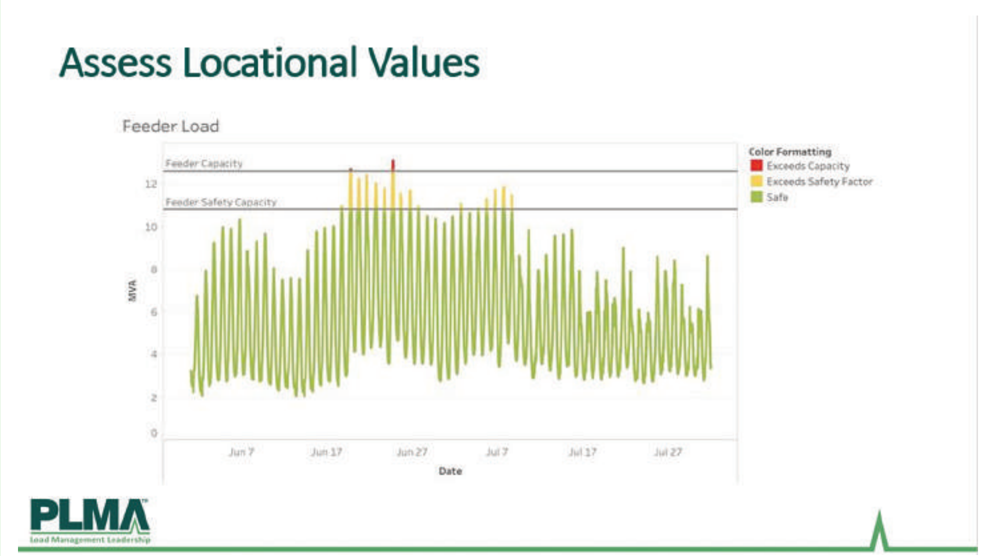
look at it as the big picture. But here, if we look at different pocket needs, it's really important to find out where you might have that value added by using some of these technologies, and some of these product lines. It's just important where one megawatt might make a big difference to distribution.



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But overall, wholesale marketing or another group might say hey, if it's not 50 megawatts or 100 megawatts, just don't bring it. But, working with those groups across silos. Breaking those barriers will definitely get you to where you need to be, with the product line that you have right now. And one thing that I like about the previous graph is that those last two lines that show, the same type of product. You don't have to roll a truck. You don't have to do any of that anymore. I mean this is just gonna be an update to a savings model optimization from your standard smart thermostat settings, so for advanced scheduling.

Hines: This kind of thing is really enabled by that granular look at the hourly shape that getting from all your measures, and what makes sense for that particular feeder. Talking to a lot of new internal stakeholders, right, Ray?

Martinez: Yeah, so breaking down barriers, I mean, definitely. I've been even very fortunate, as well as Debbie, myself, and a lot of the other groups is, we've come under one umbrella so we intermingle with these different groups. But then, within our same subgroups, we're intermingling a lot with customer solutions, customer service, understanding what they're hearing from the customers. Or trying to understand what they're hearing from the customers as it makes sense to us. The regulatory side of it, transmission and distribution. It's really important working closely with distribution planning and engineering, working closely with those other groups it's just really important. I think it's not easy. I'm very fortunate. I've been with the company I think three years, a little over three years now. So, being able to work with all these groups is a value add. But I think it's definitely not easy.

Hines: That's why some of the things like the resource heat maps. It helps everybody see the picture the same way, which really helps with getting your internal stakeholders align.

Martinez: We're still waiting for our 2018 approval for our plan. So, it's November? So maybe in December, we'll be ready for the 2018 approval. For 2019, what we're trying to do, the thought process here for the entire utility I mean Davis is been a big part of it. We talked about Jeff Yorkin with resource planning. I've been very fortunate on the DER technologies, and probably my role here with this DSM portfolio is once we get this approved, we hope to be able to launch this. I'm really excited to see what can come of it.

Hines: We tried to cram an hour's worth of presentation in a half hour for you guys, so hopefully you guys enjoyed it. Thank you for having us.

Presentation slides available at
www.peakload.org/assets/38thConf/Save-or-Shift.pdf

Three Utility Approaches to Gas Demand Response

As presented at 38th PLMA Conference in Austin, Texas on November 14, 2018

Moderator Brett Feldman, Navigant

Charles Umberger, Con Edison

Paul Wassink, National Grid

Andrew Nih, Southern California Gas Company

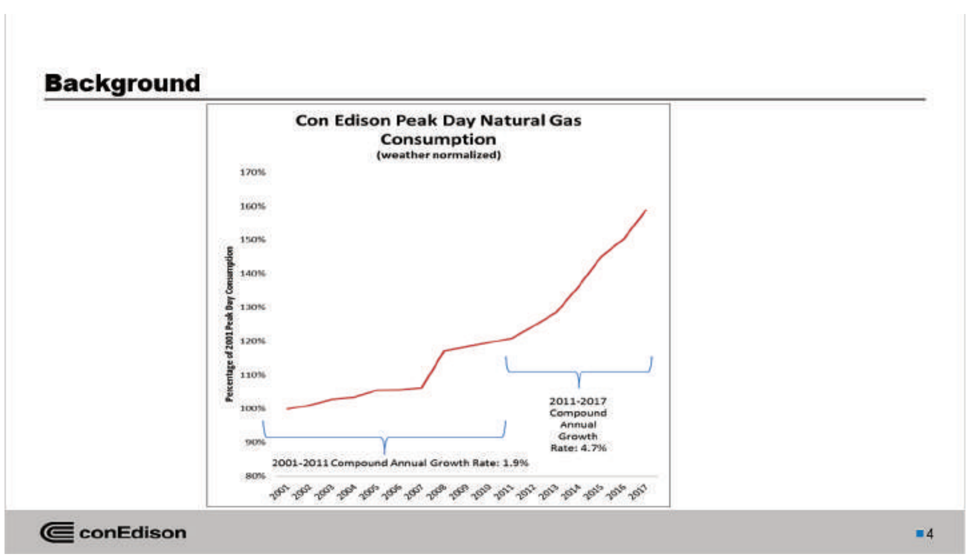
Utilities are just starting to use Demand Response to manage gas system constraints; Con Edison, National Grid, and Southern California Gas Company have all recently launched Natural Gas Demand Response Programs and Pilots. The three utilities will each give an overview of their Gas DR programs and discuss the different approaches they have taken, including the reasons for launching, an overview of the program design, results to date, as well as challenges they face and questions they are looking to answer in the early stages of these programs.

Laurie Duhan, Baltimore Gas & Electric: This panel discussion is Three Approaches to Gas Demand Response. And it's moderated by Brett Feldman, who as a research director with Navigant with 20 years of experience in the energy sector. He's the recipient of the PLMA's 2014 outstanding market research award and 2017 thought leader award.

Brett Feldman: Thanks Laurie. I believe this is the first full-fledged gas DR panel at PLMA. I know Andrew participated in a winter DR panel in Coronado, but that was also part electric. I'm sure this will be the first of many on this topic. And programs of different use cases and different customer segments and so, To introduce our panelists today, we'll have Charlie Umberger, who's a DR specialist at Con Ed and he'll talk about their C&I program that's in the early stages, just getting ready to kick off this year. And then Paul Wassink, who is a senior engineer at National Grid and he's going to talk about their C&I DR program that has a little bit of a history, so he'll get to talk about some results. And then we have Andrew Nih from SoCalGas. He is a DR and energy efficiency operations manager there and he'll give some updates on their residential gas DR program that he spoke about last time.

Charles Umberger: I'm going to talk about our performance-based gas demand response pilot. It's sort of a new topic being talked about at PLMA. But for those that are familiar with gas demand response, the big difference is the word therms. I'm going to briefly talk about the issue that we're trying to address. And then I'll go over how we are addressing it with the gas demand response pilot. Then we'll go over who is eligible, where the customers are that are eligible, and briefly what a gas demand response day looks like.

By looking at this graph [Slide 4], you can see the peak day gas needs in the Con Ed's service territory. Historically our growth rate has been lower, so around 1 to 2%, but in recent years the peak day gas needs have increased to around 4% annually. As a result of this, we have to make sure that we have enough gas for our customers on these peak days. To do this, we traditionally would have gone out and gotten more pipeline capacity or increased our reliance on delivered services. To address this with a



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nontraditional solution, we proposed a portfolio of smart solutions for natural gas customers. One of those is the natural gas demand response pilot. I'm going to focus on the performance-based gas demand response pilot but we're also offering a DLC gas demand response pilot.

The performance-based pilot is focused on C&I customers and the objective of it is to incentivize customers to reduce their peak day gas consumption. To do this, we are offering customers reservation payments for committing to reduce their peak day consumption and then performance payments for actually reducing their peak day consumption. Customers can participate using a reduction strategy of their choice. Generally, customers are going to participate by either curtailing through a thermostat setback or switching from natural gas to electric. Some industrial customers may be able to reduce process load. But one of the goals of this pilot is to really figure out how much customers can reduce their peak day gas consumption and the various methods used to do this.

As I've been saying, this is a pilot and it is time limited. We have been authorized to run the pilot for three winters and this is our first winter. Our enrollments end tomorrow, so we'll know how many therms of reduction we're going into the winter with on Friday.

So, who is eligible? The first requirement is that a customer must be a firm service customer. A customer is eligible to enroll with us if they can reduce 50 therms on these peak days. If they can't reduce 50 therms, they can enroll with an aggregator. An aggregator would also have a similar requirement where they have to enroll enough customers to reduce a total of at least 50 therms. Residential customers could also participate in this pilot if they meet the metering requirements, but we don't expect residential customers to participate in this in the short term. So, on metering, a customer has to have an interval meter so that we can create a Customer Baseline Load (CBL) to measure performance. We have four options for this. Having these four options makes it so most large customers will be able to participate and metering won't be a major obstacle. The final enrollment requirement is you can't switch from natural gas to a backup liquid fuel during a gas DR day.

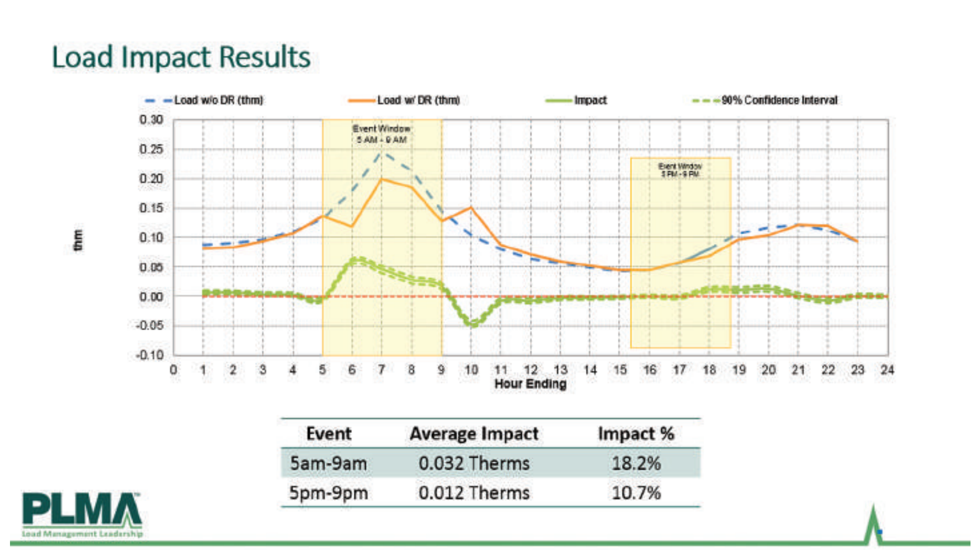
Earlier I said there are two traditional solutions to this increased demand. One is increase pipeline capacity and one is increased delivered services. When creating our incentives, we aimed to make the program cost beneficial at scale by making the incentives have the benefit of avoiding the traditional solutions. So as a result, we created incentive levels that reflect the value of Gas DR load relief in different parts of our service territory when compared to the traditional alternatives The value of load relief relative to the traditional solutions vary geographically. So as a result, we have this map of three different reservation prices. In red, you can see customers there are not eligible. If customers located in that area reduce load on a peak day, it wouldn't create value by avoiding the traditional solutions. Zone A in green, that's the highest value zone. Load relief there contributes to a decreased need of pipeline capacity and avoided delivered services. And then zone B, that has less value than zone A, but there's still value there.

So finally, what is a gas DR day? So, a gas DR day happens between November 1st and March 30th. Based on the past few years, we expect three to four events per year. And finally, the biggest departure from our electric program is a call window. As I've been saying, this is a supply issue that spans a 24-hour period during a gas day. When a customer responds, there needs to be a net reduction over the 24-hour period during a gas day, and that's from 10am to 10am. So, with that, I'm going to pass it on to Andrew.

Andrew Nih: Good afternoon everyone, and just glad to be back here. As Brett mentioned earlier, I did give a talk at the last PLMA Conference in Coronado on our gas DR program. But today, I actually have some results to share. And there's, sorry there is only one slide on the results but there is a publicly available impact evaluation if you're all interested in the results afterwards. Operational limitations on our system, due to various reasons. Number one, we have limited usage of our storage fields. As some of may you, we cannot use that storage field to its full capacity. Number two, we have some operational limitations due to a pipeline allergist that are undergoing heavy maintenance. And so, that's going to limit some capacity that we can bring into the SoCal area. And so, those two really are the biggest reasons why we're doing gas demand response. And we do foresee doing the gas demand response for the near-term future to where, at least for this winter, we don't think that we would be able to meet a 1 in 35 peak day event demand period.

Just to remind you all about what our program entailed last winter. Customers received $50 for enrolling in the program. And again, this is smart thermostats and only for residential customers. They received $25 just for staying in the program. There was no penalty if they adjusted out of the temperature adjustments. Our events were between 5:00am to 9:00am in the morning, and 5:00pm to 9:00pm at night. Overall, we enrolled 9,200 customers with about 10,800 thermostats. And those were mainly Nest and Ecobee thermostats last winter.

Over February, we actually called about 13 events within a span of 2 weeks, and there were actually four days where we called events for both the morning and evening period. We actually called about 13 events within a span of two weeks. And there were actually four days where we called events for both the morning and evening period. And so, as you can imagine, we got a lot of customer complaints about hey, I'm too cold, please how do I override the adjustment? And so, that was very fun to have to take all of those calls. But I think I shared this last time, on average, about 60% of our customers who were participants participate in a full four hours of the events. Whereas 40% either never got the signal due to incompatibility reasons. They overrode the events either before or after. Or for some odd reason just didn't want to participate.



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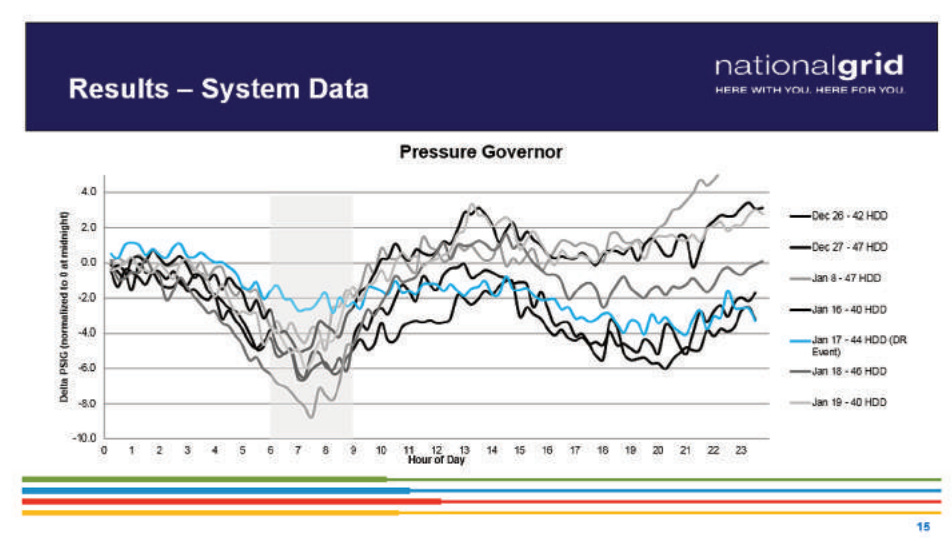
Here's the main slide that I really wanted to show you all. [Slide 12] As you can see at the bottom, there's some average impact per customer. It too, as you can see on the impact percentage, 18.2% per customer. During those four-hour periods in the morning event time period. And then, 10.7 during the evening period. There is a publicly-available impact evaluation report at [www.calmac.com/]. But just two little things that I want to, maybe not little, but two areas I want to just pinpoint as you look at this graph. You can see that the snapback right after the event windows we're pretty, I don't want to say significant, but that's what caught the eye of our regulators and our evaluator. And so, you can see in the morning period right at hour ten as all the thermostats in the morning period right at hour ten as all the thermostats were set back to the original set point, there is that snap back as the homes try to get back up to the proper temperature. And in the evening period, and sorry, that event window is not in the right place at the moment. But if you look at hour 21, which is 10 o'clock, you'll see that in some instances we actually created a new peak. That the snap back created a new peak during the evening period to where those participants were using more gas than what they would have originally used anyways. And so, we are taking these results. We're going to apply some new strategies this upcoming winter to see if we can lower that snap back and try to get some more participation in our program.

Wassink: All right, same thing, slightly different flavor of gas demand response. My ice cream flavor is very similar to ConEd. We are doing commercial, industrial, customer gas demand response pilot only in Long Island. Key difference between ours and his is ConEd is for a whole day and ours is only for three hours. We thought we'd get a lot more customer participation with three hours. So how do we do it? I kind of see this program broken up into two questions. Can we do it, and why would we do it? And they're both good questions. We've identified the can we do it part in the first year. So, we have direct load control on C&I boilers, and we can shut them down, we can get the telemetry back, we can do measurement verification. So, check box. Gas demand response can be done. What we're still working on this year, with a few consultants, is why would we do it? So, you can definitely have a system benefit if you can shut off somebody's gas for more than a day. But very few customers can have the gas turned off for a whole day. And if they can, they often want to switch off to the diesel boiler or natural gas boiler. Well, our environmentally friendly regulators don't like diesel boilers. And if you're just switching to natural gas on a system that primarily uses electricity with natural gas, you're not really helping anything. You're just moving from one thing to another, maybe stored gas or whatever. So, a few of the results. [Slide 15] That little blue squiggly line there, this is measuring pressure on our gas network. So, when demand is high, pressure goes low. If it goes too low, we have a problem, so this is just the result. The blue line is for the customers who participated. So, pressure didn't go down as far as it otherwise would. We were



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able to at least keep the pressure on the system going down too far. On this particular part of our gas network, it doesn't really hurt anything if the pressure goes down that low. But you could definitely imagine a special area of your network where maybe you're gaining a lot more gas customers on the network than before. And you might have to do a reinforcement project to accept the new customers. Well, maybe gas demand response could be used for those special areas. Like I said, we're still looking into that.

Feldman: The first question that I wanted to talk about was baselines. Can each of you talk about how baselines were developed.

Umberger: As I was saying earlier, our gas demand response events are 24 hours, from 10 AM to 10 AM. Which means we have to have a baseline that covers a 24-hour period. So, to do that, we looked at a bunch of options and ended up with an option that is very similar to the CBL method that we use on the electric side. On the electric side, we have a CBL that, on the weekday, it looks at the ten previous weekdays. And finds the ten similar weekdays, and then looks at the five highest. So, we applied the same CBL method to gas.

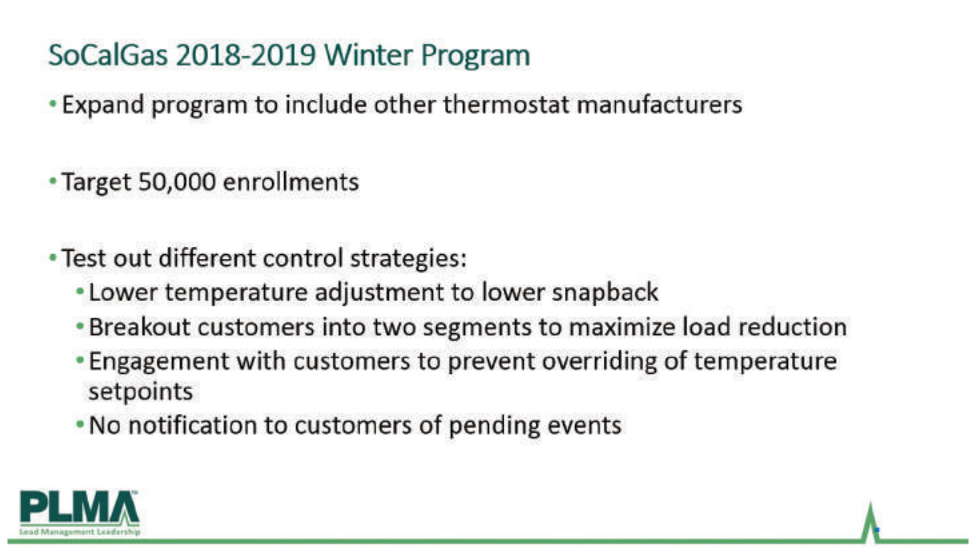
Wassink: We just did it on nameplate capacity the first year. So when you turn people off, we just assumed that a certain size boiler had a certain size curtailment. However, we do hope to catch up to Con Ed this year. We use the last ten of ten baseline with a weather adjustment.

Nih: Our evaluator utilizes the same technology that they use on the electric side. Smart thermostats, comparing participants with non-participants to figure out the baseline and the thermal savings.

Feldman: Andrew talked a little bit about snapback. Did you want to say anything else about how you're looking to address that?

Nih: There are different strategies that we're going to try to help us address that snapback that I was mentioning earlier. Number one, as you can see ere, [Slide 22] is lowering the temperature adjustment from four degrees to possibly three and seeing if that will help. Also we're looking at breaking our customers into different groups, depending on their usage. And a couple other different strategies. Potentially not notifying customers of pending events. Obviously, those will help with the snapback. But just something different that we're going to try this winter.

Umberger: With our program, it's going to definitely be something that we try to address. Our electric customers,



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the electric DR customers that are used to four-hour events or six-hour events. Where they can just shift load, or just turn on a backup generator. For gas DR, you could have a four-hour strategy. But if that four-hour strategy is then just resulting in increasing consumption later in the day, that's going to be an issue. So, at the end of our season, we'll talk with our customers and figure out what strategies resulted in snapback, which ones didn't result in snapback. And then we'll communicate it to the participants.

Wassink: We didn't see much snapback, we went back to that low-pressure curve. It went up slightly afterwards, but not much at all. So at least for our C&I customers for three-hour events, it didn't seem to be a problem.

Feldman: Would each of you can talk about your incentive structure?

Umberger: Our incentive structure is quite simple. We have reservation and performance incentives. The reservation incentives are for customers that commit to reduce a certain quantity of therms on a peak load day. We have a $9 incentive for customers in that high-value zone and a $5 incentive per therm per day in the low-value zone.

This is a quick example: [Slide 21] If you have one customer that enrolls in the pilot for 100 therms and they enroll in the high-value zone, then the reservation rate will be $9 per therm. This means they would be getting $9 times 100 therms times 5 months and would get $4,500 for participation. This assumes the customer performs at 100% during all events. If they don't perform at 100%, then the reservation payments would be derated using a performance factor. The customer would also get $1 per therm reduced during events.

Nih: A customer can up to $75, a new customer, $50 for enrolling and $25 for staying with us through the whole winter. Any returning customers will receive that $25.

Feldman: How do you do the cost recovery for your programs?

Umberger: So we filed with the Public Service Commission and we asked for a budget to spend over the next three years. We have around $5 million dollars to spend on this program and the DLC program, and the money that we spend through this program will be recovered using the monthly revenue adjustment. This is a pass-through account.

Nih: We are in discussions with our commission about how to recover the costs. But we anticipate being able to recover all this through our public purpose surcharge.

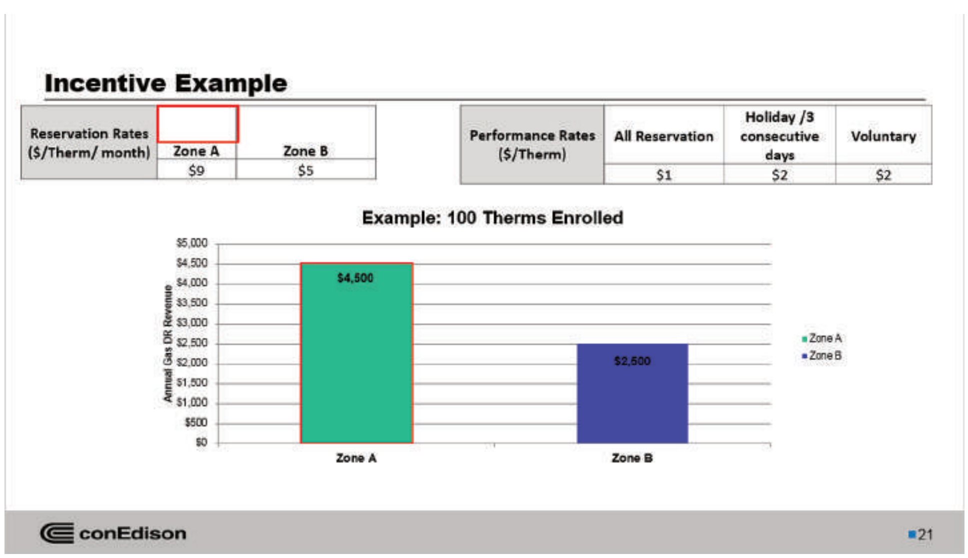
Wassink: For us, same as Con Ed, it's a demonstration project, it was a separate filing. We get to recover all of it. National Grid shareholders aren't making anything off of this yet, but we're hoping that if it proves out, it'll become another energy efficiency option that will join our portfolio of options. And we can make shareholder profits the way we do typically through our EE programs.

Feldman: So just looking ahead a little bit, I know Charlie's just getting into his first season but, Andrew and Paul, if you can talk a little bit about looking forward and what you've learned and what you're looking to expand to.

Nih: Our new target is 50,000 enrollments and we're expanding to other thermostats as well.

Wassink: We're expanding our program to Rhode Island, a similar pilot demonstration. [Slide 23] And we're doing a big step up on more of the analysis side, on what are the system benefits of doing this kind of short-term gas demand response.

Mark Sclafani, Central Hudson Gas and Electric: I have a question for Andrew. I was wondering, it seems like you did two different event periods, one early in the morning, and one later in the evening. Was there a big difference between the way customers were receptive to early morning versus an evening event? Did you have more overrides or complaints and issues in one versus the other?



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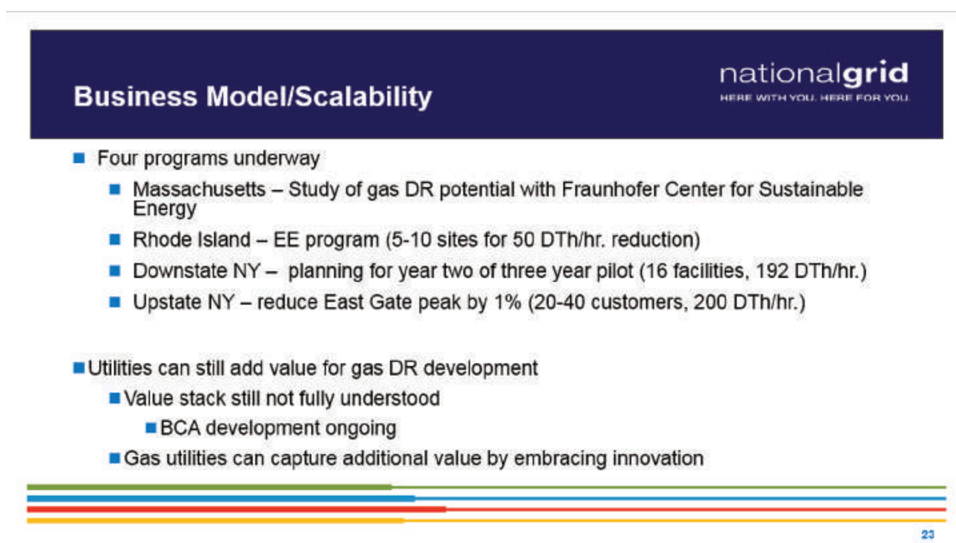

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Nih: We've definitely saw more participation in the morning period, more impact. And the reason we found out, or as if we were looking at the data, is that most people did not turn on their heaters or their furnaces during the evening period. Because the home had all the heating from the daytime period to warm up. The morning was definitely the more impactful. But that also meant that we got more complaints in the morning, right? People were waking up to cold homes. People had elderly parents or children that needed the warmth. Which is fine with us, we just don't want you in the program anymore. For some customers this program's going to work and for others it's not going to work and, you know, I'm sure we all understand that.

Sclafani: How did you determine what was the right incentive to offer? And how did you arrive at what the incentives are in the program?

Umberger: For Con Ed, we had a bunch of factors. One was: What's the alternative? So, we had delivered services, and we had pipeline capacity. Knowing the price of the alternatives, we had to create a reservation incentive that would pass a BCA.

Nih: We use the electric programs as a model to start off with. But really it was just trying to determine that the appropriate financial incentive for customers to enroll in the program. And what had happened was our regulators asked us to increase the enrollment fee. We originally were going to offer $25 but they made us increase it to $50.

Wassink: That's a great question. Usually incentives are scaled based on the system benefits but we haven't calculated those yet. So, we just looked at our electric programs and said, what makes a customer move on the electric side? When you translate that to therms, what do we need per year to incentivize these customers and get in on that?

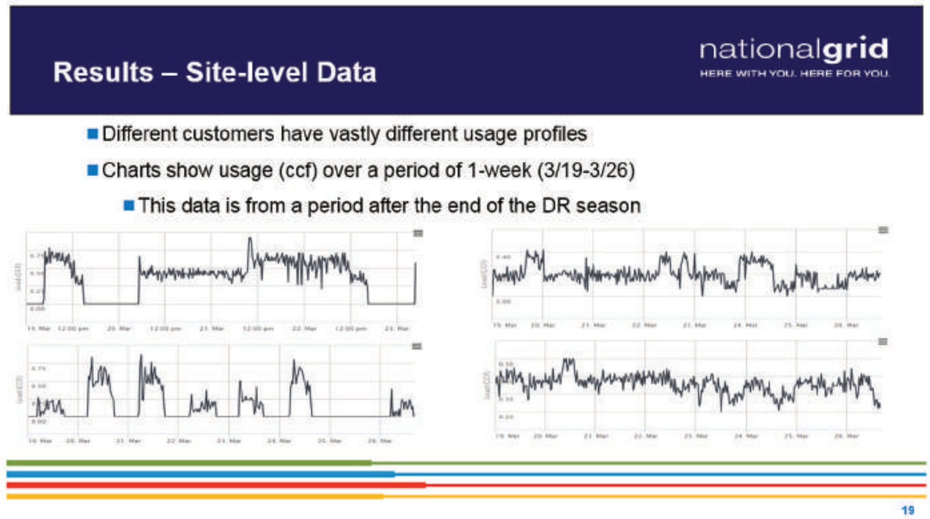
Audience member: For the residential program did you consider preheating the home or preconditioning the space?

Nih: The Nest thermostats actually did preheat the home beforehand and actually when you do look at the results in the impact evaluation, I think what you'll see is that. There were some differences between preheating and non-preheating thermostats. But that is definitely something we did consider, and we will be trying again this upcoming winter.

Feldman: If you coordinated with some of the electric utilities in your territory, what are some of the similarities or differences between electric and gas DR and how do you work that into the program design?

Umberger: We designed the Gas DR Pilot to be similar to our Electric DR program and the outcome is the participants are very familiar with the design. Since our electric program utilizes an aggregator model, we incorporated aggregators in our Gas pilot. Since we already have relationships with the aggregators, we were able to reach out to all the aggregators that participate on the electric side, and let them know about gas DR. And they're like, oh, that's really pretty easy. The incentive structure is identical, so we have reservation prices and for performance payments. I mean pretty much the entire program is identical to our electric program. And it's not just aggregators that get it. We don't have a ton of direct participants in our electric program, but a few of the ones that are direct participants, meaning just individual buildings, they enrolled in the gas DR pilot. So, I think keeping it similar to our electric program had a huge benefit.

Wassink: We tried to model off the electric with one big difference On the electric side, we don't have AMI but we do have 15-minute interval data on all our large C&I customers. So, when we're looking to enroll customers in our electric DR programs, we can look forward to discretionary patterns. C&I customers have large process loads that go on and go off. Historically, those have



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been the most successful. But we don't have that typically on the gas side, best we'll have hourly data. But as part of this program, we did put interval meters, one-minute gas interval meters on 30 of the participants. And we did find something similar. So, in these two graphs, you can see how these customers are using gas and then they're not, they're down. [Slide 19] So on the left graph is a process customer and that's a process that's down and then they go up again versus the customers on the other side, those are HVAC based customers, so they're just heating. So, it's the load is a lot more discretionary for the process load customers than the HVAC load customers. So, this gives us another compelling reason when we go to our regulators for better meter equipment in the field, so we can do this kind of, this splitting of customer profiles.

Nih: I welcome any thoughts you guys have about comparing my program versus electric DR smart thermostat program. But I think that now that we actually have a season's worth of data, we can actually start to tailor our strategies specific to how our residents use natural gas.

Audience member: It looks to me like you guys are using gas DR to solve kind of different problems, so. In New York, it seems like it's pipeline capacity based, and in California it's a bit of pipeline capacity and actual supply challenges. Are there any other value streams you guys are looking at using gas DR for? I think I saw that comment on one of the last slides. Just like electricity might have capacity and energy and then ancillary services or frequency regulation. What's the frequency regulation, if you will, of gas that you guys might be thinking about on your side?

Umberger: I think we are very far from this, and this is just Charlie thinking. But you know how we had the zones? The zone that's at the top that is identified as no value because it's not offering benefits to decreasing our reliance on delivered services or pipeline capacity. That area really just has the right amount of capacity. But if that area were to have 50% too much, we could potentially sell that extra capacity. So, in the future potentially that could happen, but you'd have to be able to reduce significantly more than what we are doing. There may be regulatory issues I'm not familiar with that prohibit us from doing this.

Wassink: And I'm hoping out of our study for next year, one of the things we'll find is that there's a demand response induced price effect to gas DR. So, we see that a lot on our electric side where we decrease energy use at peak times. The wholesale prices go down, everybody saves. Since a majority of our electric generation is natural gas, if we move as natural gas prices go up electric prices go up just because they're both using the same fuel. So intuitively it feels like gas DR should have demand response price effect. I haven't been able to prove it yet either.

Nih: And that for us was strictly to address our operational limitations for now, and then we keep hearing about non-pipeline solutions. That's certainly not what we were using this response for, but if it ever got to that point, potentially. But for now, it's strictly on operational limitations.

Feldman: That is one of the big differences between electric and gas. On the gas side, you don't have that same kind of transparent wholesale market. There are wholesale transactions but you don't have the different things like capacity in energy and ancillary services and I don't know if there's a need for any kind of fast response gas DR at this point.

Steve Cowell, E4TheFuture: How have you compared and integrated, or looked at, energy efficiency work for customer X versus demand response for customer X versus both? And have you looked at the impact of doing one approach i.e., putting in insulation, and so they lower their therm use for and then do demand response. How have you integrated those two strategies, or have you kept them separate for now?

Nih: We are just starting to look at that. We are starting to integrate EE and DER at the same time that we're at the customers' homes already. Obviously, on the electric side, I think that's been happening for years now. But yeah, getting to the customer at the same time would be beneficial to install both EE and DER. Like you said, EE would be more permanent but DRs, when we need or specifically need for that specific period and that will tremendously help.

Wassink: For us on the C&I side, DR is just another EE. It's the same sales reps selling it. So, when they go to a C&I customer, I mean, right now this was a pilot program. So, it's not open to everybody, but if it did open up, they're going to go to that customer and they're going to say, well, your boiler is bfd or hey, have you done demand response? So, we're using the exact same sales, the exact same sales force and the exact same relationships, all the resources, DR is just another EE for us.

Umberger: So first, we have an aggregator model. So, aggregators will go and get the customers, and some of our aggregators offer other services. So, it's very easy to go from offering a BMS system to offering to use the BMS system to help reduce load on peak day. I'll also say that DR is one of the many ways that we're addressing the peak day demand. We offer four different solutions, which are part of our smart solutions for natural gas customers which consists of an enhanced energy efficiency portfolio, a non-pipelines solution RFP, an innovative solutions RFI, and then gas DR.

Cowell: While they're changing from DR to active demand management, that's the new buzzword, active demand management. And it's being all integrated with efficiency. We'll see how our friends at National Grid enjoy that.

Wassink: It means the same thing. And we pushed just to call it the same thing. Active demand management, demand response, I don't think we need a new term in the industry but, you're welcome.

Feldman: I was going to say, another acronym. On the electric side, there was a lot more of the AMI out there, so on the gas side, how prevalent is that, and what can you do without having that for DR?

Umberger: So, we were pleasantly surprised. So, with electric DR the biggest, I don't want to say pain point, but it's a pain point, just getting interval data. So, on the gas side, we weren't really aware of all of the metering options. But we discovered that we have four: AMI meters, volume correctors, customer owned data recording devices, and AMI IMU's. So, we are currently doing an AMI roll out. So, all the customers that have already been given gas AMI meters, they were eligible to participate. We discovered that large gas customers have volume correctors, and these volume correctors do a few things, and one of them is record hourly interval data. So, with all of the enrollments that we have so far, the volume corrector option is used the most. Many large customers are already recording their hourly interval data so we're allowing them the option of just submitting that to us for this pilot phase. And the fourth option is an AMI IMU. AMI consists of the meters and communications infrastructure. We can install meters without communications infrastructure that record the interval data. So, for certain customers that are large enough, we're offering to install the AMI meters and then we will manually go and get the data until the communications infrastructure is in place.

Nih: We have actually completed our rollout of AMI meters to all of our customers. So hourly meter data is available to us too.

Robin Maslowski, Navigant: Charlie, what end uses and strategies do you think customers are going to use to respond to a 24-hour event without having snap back that absorbs the entire reduction?

Umberger: All right, so I can go through the options that customers have told us that they're going to be doing. So, we have large commercial customers who will just be shutting off their commercial processes for the 24-hour period. Assuming they don't turn it back on first thing in the morning, before 10 AM, there really shouldn't be snapback that impacts our peak day. If it snaps back the next day after 10am, that's okay if the next day isn't also a demand response day. Second option, could be. If a customer were to just reduce at the tail end of a one-day event. This strategy would reduce the current day's peak demand and the snap back would be pushed to the next day. A third option could be getting to an evening load earlier in the day. For example, if a commercial building starts to have reduced occupation around 5 o'clock, but they really start setting back the heat a few hours later, there is an opportunity for savings there. If they'd just start shutting down a little bit earlier and get to their nighttime base load earlier, that could help create savings that also avoid snap back since the morning ramp should be similar to a non–Gas DR event day load. A fifth option could be consistent modest thermostat set back. A sixth option could be not using and heating recreational spaces, such as an indoor pool. Finally, if you have a CHP unit you could adjust your CHP usage to get natural gas savings. There are a few options, but we look forward to hearing about more. It should also be noted that each of these strategies will have different impacts based on occupancy on these cold days and the building stock of participants.

Feldman: Thanks to the panel. I'll just give a quick plug we just added some gas DR content into the DR program design training that PLMA offers. So, you can look out for that if you attend that course. Details at www.peakload.org/demand-response-training

Presentation slides available at
www.peakload.org/assets/38thConf/Three-Utility-Approaches-to-Gas-Demand-Response.pdf