Load Management Leadership

Practitioner Perspectives™

Thought Leadership 2019

A Compendium of Industry Viewpoints

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PLMA (Peak Load Management Alliance) was founded in 1999 as the voice of load management practitioners and has grown to over 150 utility and allied organization members. PLMA is a community of experts and practitioners dedicated to sharing knowledge and providing resources to promote inclusiveness in the design, delivery, technology, and management of solutions addressing energy and natural resource integration. The non-profit association provides a forum for practitioners to share dynamic load management expertise, including demand response and distributed energy resources. PLMA members share expertise to educate each other and explore innovative approaches to load management programs, price and rate response, regional regulatory issues, and technologies as the energy markets evolve. PLMA will continue to maintain a forum where practical experience, ideas, and knowledge are promoted to those seeking access to a vast network of industry professionals and practitioners. It is also a place where members gather to keep abreast of the latest industry trends in load management and to inform the next generation. We offer timely subject matter and training opportunities to address key facets of our industry charge. Membership in PLMA is open to any organization interested in load management. PLMA represents a broad range of energy professionals and industries–private and publicly owned utilities, technology companies, energy and energy solution providers, equipment manufacturers, research organizations, consultants, and consumers. Learn more at www.peakload.org

PLMA Thought Leadership Planning Group

Chaired by Richard Philip, Duke Energy and Jenny Roehm, Schneider Electric

This group guides the PLMA Strategic Vision to Accelerate PLMA Thought Leadership Through More Aggressive Pursuit of Speaking Opportunities and Regular Creation of Meaningful Content.

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.

Group Activities include: a Resource Directory at www.peakload.org/resource-directory and a Speaker Bureau at www.peakload.org/speakers-bureau.

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Load Management Leadership

THOUGHT LEADERSHIP

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Table of Contents

The Future of Distributed Resources Compendium

From 39th PLMA Conference


Richard Philip
Duke Energy


Michael Brown
Berkshire Hathaway
NV Energy


Richard Barone
Hawaiian Electric
Company


John Powers
Extensible Energy


Jenny Roehm
Schneider Electric

Michael Brown: One of PLMA's key strategic initiatives is to drive DER adoption and integration. And so, Jenny and Rich are co-chairs of our Thought Leadership Group and John and Richard Barone are co-chairs of our DER Integration Interest Group. As part of our best practices outreach strategy, these two groups spearheaded this publication.

The publication is also a way to get input from our members of the industry. We requested that abstracts be submitted. We had a planning review community that selected the abstracts that are in this publication. We distilled those down into a number of categories and we're going to cover those in a little bit. One of the key goals is that we want to enable our members with some tools to share at their own organizations or share with their executives, particularly if they have questions about what their organizations need to be doing to move things forward or what some strategic ideas. We're hoping that this publication can be a tool for our members to help them do that.

I would like to hand it now over to Rich Phillip, he's going to give us a little more insight into the different types of papers, the eight case studies in there, the different types that we have and the key categories that we covered.

Richard Phillip: As we reviewed abstract submissions, we noticed the type and variety of projects that were represented. We landed on a consensus: "These abstracts seem to fall into four categories... " Well, actually we talked about how they fall into three categories and then realized that there always somebody that doesn't quite fit, right?

The first category is Planning and Foundational. These projects are focused on how all this change with DERs going to impact how utilities plan the grid and their systems and even what they will do in the future. Reflecting that this change is really shaking the foundation of what the business has been like. DR Plus is a category of projects that were taking existing DR resources, often longstanding legacy programs, and trying to use those instead of as a global resource to help a generation or large scale transmission issues, be able to drive it closer to the ground and help with distribution level problems.

Microgrids is a category that grouped projects where entities were looking to create alternatives to sometimes some tricky services issues. Then the fourth category is International. We had a submission that was about an international situation in Columbia. It didn't fit clearly into any of those other categories. It actually probably crossed several of the categories, and we determined that categorizing it separately was the right thing to do. So, the report is organized that way and some of our conversation right now is going to be organized that way too.

Richard Barone, can you take us through some of the things in the Planning and Foundational group?

Richard Barone: Look, this is a fine line here. I want to shop this product without giving away too much because I want everybody to pick it up and read through it. What I will do is look at this integrated planning section, there's three case studies in there, and just thematically tease out what pops up across the three of them. The three cases studies are, Hawaiian Electric's integrated grid planning, Portland General Electric, and Tacoma Power.

The two main themes that you'll see through these is, with the evolution of planning there's a couple of the case studies is emphasize the bulk system, IRP element, and then the distribution resource planning element and how these things work together.

The complimentary component that's germane to this conversation is how do distributed energy resources fit into that model. I like the term used in the Tacoma Power, which is The Power Supply of The Future. It's looking at these resources in the context of these evolving planning techniques, but also looking at what are the populations of these technologies relative to how we can incentivize folks to participate in the DER, so this becomes a feedback loop, lends itself to the complexity of these planning methodologies. But it is the holistic approach that, I think as we go into the future, we're going to continuously have to undertake as utilities.

So that's the general high level theme. Michael and I were talking about this yesterday, the non-obvious part of these case studies, as you read through them, I would love for folks to consider is that, this is also a change management exercise. Change management in particular for utilities who have never really had to do a deep dive into what the distributed assets mean from a system resource planning and operations perspectives. I think thematically, those are the three big triangles of themes in these three case studies and I encourage you all to pick it up and read through them.

Phillip: The second category we're going to talk about is DR Plus. John, what are the major takeaways from that grouping?

John Powers: Certainly people talk about DR Plus as being DER behind the meter, just using DR as a monetization mechanism for allowing DERs to participate in markets. That buries some of the complexity and opportunities in that space. I'll just talk about two of the case studies that are in the report to bracket the space a little bit. One was a National Grid case study about taking a functioning, excellent, performing Bring Your Own Thermostat program and, oh you know, just add batteries to it.

Now just adding batteries to a bring your own thermostat expands it to an innovative Bring Your Own Device project and it allowed them to put customer-owned storage assets in residential homes behind the meter on the same type of incentive per kilowatt reduction, or kilowatt shift, as an existing program. It was very smart to leverage existing customer participation, DERMS, all the other parts that are part of a utility demand response program with a new set of DER resources.

The other one is a California study. So, Californians like to many things complicated. We all talk about the possibilities of DERs participating in wholesale markets. This project... I'm just going to call it out as project four because it's got a very long title and eight co-authors or something. The idea was to get two portfolios of buildings that have different behind-the-meter assets, some were storage, some were just controllable HVAC loads and other loads behind the meter, and to then bid those into the California ISO in the day ahead and real time energy markets as what are called proxy demand resources. Please don't ask me to say any more about the California markets. But the idea was to actually go all the way from behind the meter to revenue from the California ISO without working through a utility. All of this was done without utility program involvement. So, this is DERs, behind the meter, bidding directly into the California ISO for money. Those are pretty extreme differences between how DER's will participate in DR markets, or other markets. I'll let you compare and contrast when you get this report and read it.

Phillip: Michael, there are some interesting things going on in the Microgrid space. What things were shared in this report?

Brown: We felt the microgrid space was very important. I know at NV Energy it's probably every other week we get a question from a customer about what kind of support we have for microgrids, even residential developers looking to build new communities that they want to take off of the grid and supply folks with renewable power. In this report we see a span there. We had two case studies. One case study at Fort Custer, with the Michigan National Army Guard, that did a collaborative project with Consumers Energy. And then another one in an apartment complex in Brooklyn, Queens. So, in the Microgrids category, both of those projects are taking advantage of the opportunity to sell services or interact with the utility to value those services and monetize some of the services to help pay for the microgrid.

At Fort Custer, they were looking to enhance their resiliency. They had some old diesel generators and they needed to upgrade so they added storage and PV. And then Eaton came in and helped them put together the microgrid. Very sophisticated controls we're looking at, lots of upfront simulation and planning to make that work and then on a little bit smaller scale in Brooklyn, the fuel cell–300 kW at 1,200 of kWh–battery. We like that because it requires a lot of coordination. Increasingly we're seeing at the building level new sorts of co-optimization software. We think that's a big theme and that case study encapsulates that, these new products, new ways of coordinating the resources or coming to market.

I'll just finish up with a true story. About a week and a half ago at a team meeting with the new SVP in charge of the renewables–we're projecting we're going to be at 50% renewables by 2023–so, we're in a team meeting and somebody pipes up and says, "Well, there is a colonel at the Creech (it's an air force base) that wants to meet with you today. He wants to talk about resiliency and microgrid project. He really didn't say much." And so, I say, "Okay, okay." That was my opportunity to pull this report out and point to that case study and say, "If you want to learn a little bit more about this, read this case study and if you want some more information I know the folks... I can connect you with the folks at PLMA to dig into this and help you get some more information." That's one of the ways we're hoping that this report will help.

Phillip: Thanks for that extra story at the end because, without a doubt, one of the goals from Thought Leadership in PLMA was for members to be able to use this report as something to educate "management" within our organizations and help them understand how these things fit together. Many of us are quite comfortable with what we do within the DR space and as we branch out broader in that space, we can use a report like this, to try to get levels above us to see DR capabilities in a different light. Because sometimes they may have an old school thought about what is done or can be done and don't fully appreciate how we can enable the future. For that reason, I think a report like this is exactly what our membership needs.

The last category is international. Jenny, what types of things do you want to share from this project?

Jenny Roehm: One of the case studies in the compendium is from Columbia. It was really interesting to see the parallels and differences to projects in North America. One of the reasons to read case studies like this is to see how other people tackle the same problems we're facing. And in looking at both the opportunities and the barriers of what was going on with DR in Columbia, there were several things that came out that are very familiar to us: the regulatory environment makes a difference; there are struggles with contracting for some of these really long-term resources; how to incentivize customers, either through the utility or otherwise; and how to install DERs and let them be used for grid stability.

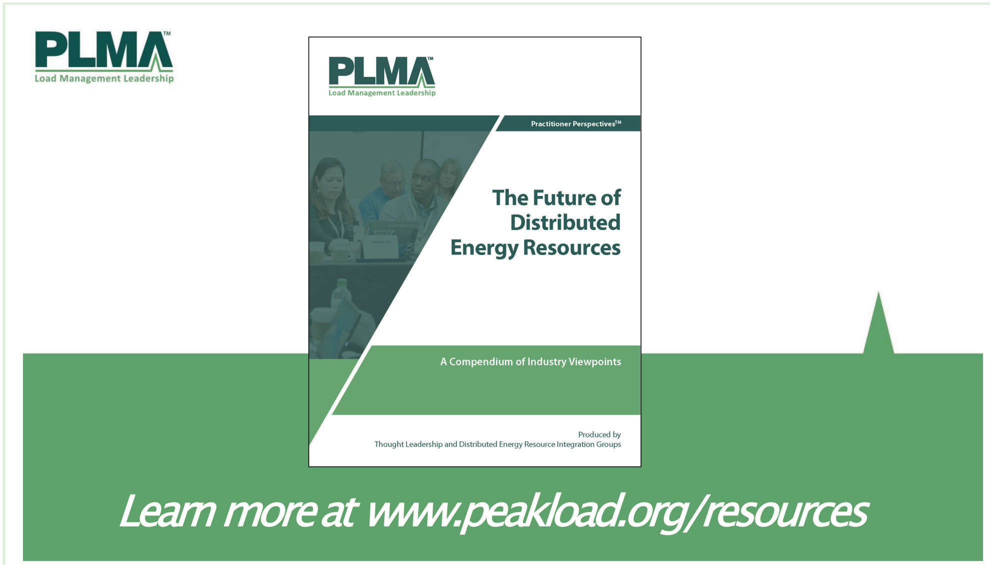
So, while it's an entirely different country, on an entirely different continent, there are parallels. And actually, people can get creative and find solutions to these problems in ways that will spark some ideas. I encourage you guys to read, it but I think that was what I got the most out of it, is the parallels to the issues that we face here.

Brown: Just to add on to that, there's a huge opportunity for DER growth around the world. That's where most of the growth in DER will be, in emerging markets as countries are electrifying and trying to integrate these resources to the grid. We felt that was important. I'm going to kick this off with just a few questions.

First question to the panel here, is in terms of technology, which set of technology do we believe are going to be next greatest thing in this field of DER to help us with adoptions? When you think of technologies what comes to mind when you think of the future of DER?

Powers: The theme we keep seeing is that load flexibility is valuable. As the more nondispatchable resources are placed on the grid, on the resource side, the more flexible the load side has to become. And that's something we've all been doing in one form or another for a long time. So, load flexibility now though means the ability to get away from event-based or emergency-based DR programs and into continuous or, what I've been calling, objective-based load flexibility so you're able to manage loads. We did an exercise yesterday where we expected multiple hundreds of calls for this batch per year, so that's not something you just say, "There's an emergency tomorrow. Cut off your AC." It's more like, "This is how loads are going to have to behave from now on."

The folks who buy batteries for resiliency purposes will be contributing to that, but I think that in many cases behind-the-meter, small account batteries don't make sense economically yet. So, it's much more about leveraging what's already in place, so heating and cooling, batteries that are bought for resiliency and other things. I think that's the place we're seeing the most likely uptake in the next five to 10 years.



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Roehm: One thing that will make a huge difference with DERs in the future is advances in machine learning. Because we're having to be much more flexible and be more responsive, the loads are going to have to be engaged within seconds, not day ahead, not 10 minutes, or "By the way, can you?" Call it artificial intelligence or machine learning, I think that's going to be one of the places that will make a big difference in the adoption because that makes all of those distributed resources able to be combined in such a way that you actually have a whole resource.

Powers: And it has to be, right, because you can't have continuous dispatch of loads being done ad hoc. It has to be done in an automated fashion and it has to be done other than somebody throwing a big lever. It's got to be automated using some form of artificial intelligence to pick the times to dispatch the things I was just talking about.

Roehm: Otherwise pushing the button would look a lot like whack-a-mole.

Barone: I concur 100% but I think I would look technologically at the IT side and the end use side, the IT side though less obvious. A lot of us are focused on programmatic approaches and customer assets, so just touching there, nothing revolutionary. I'm directly witnessing this in Hawaii, storage is going to become an increasingly important and revolutionary flexible load asset given the penetration and populations. If you look at the nexus of storage with electrification or transportation as big initiatives in different jurisdictions, electric vehicles are going to be a very important load flexibility contributor with obvious degrees of complexity around mobility, which lends itself to some of the artificial intelligence and machine learning that Jenny alluded to.

That's on the–you might call it the OT side. But for this stuff to all play an important role relative to some of the integrated planning and the manifestation of that planning and the reality of operating grids, the IT side and the evolution and commingling of energy management systems, advanced distribution management systems, and DERMS and how these things sort themselves out. To take advantage of that visibility and to take advantage of that flexibly and put it into the operation hands of our system operators is going to be linchpin in the next quantum leap in the contribution of these resources to grid management.

Roehm: I would say there is one more element that is actually going to be important is, with all of these distributed resources you have to figure out how to pay people. You have to figure out how you're actually going to incentive them. If you're doing these microtransactions, how are you going to track that and pay for that? While it's not quite all the rage anymore but something like blockchain and being able to do transactions is going to be the other part that's going to make it happen. We have the technology but until you actually motivate people, it's not going to have uptake.

Brown: We're going to switch a little bit away from technology and dig into your thoughts about regulations or regulatory issues. How do you see regulations either hindering or helping to further the adoption of DER?

Phillip: Richard Barone will talk about what it's like in places where they're already living with these changes today. In my experience, when there has been major change in our industry, the regulators have been steps behind in the process because they usually want to know what the future will look before setting any rules.

It's something that has to be worked through. We now have the Internet of Things. We also live in a time where the cost of solar has been dropping precipitously and batteries for the first time in history are becoming a cost efficient investment for utilities and customers. The whole construct of what a utility is based upon is being challenged. In many cases, state regulators are political appointees or elected. Often, a "newer" commissioner really just barely understands how the business has been for the last 100 years–let alone deal with the implications of change in this magnitude. I'm not harpooning them on that, it is a complicated and often wonky business, but it is the real world for many of us in the utility business.

For utilities to deal with the level of change being enabled by technology, that customers are demanding, and the new flood of potential solutions–is quite challenging. To then deal with regulators who fall all across the spectrum of experience and understanding is not simple. Sometimes there is somebody out in the regulatory space that likes the sound of the bright shiny new thing that's going on and wants to prod us in that direction by saying, "Hey, you stodgy old utility, you should be looking at new things."

But there are others that just see risk and political risk and all the things that go with that. This is, I think, exactly what we're balancing upon right now as we're trying to figure out t the right way to go. I think our customers are dragging us there–which is how change often comes.

Keep in the mind that there are a lot of voices in the regulatory process, each is representing their own interests. Whether it is the utilities, technology/service providers, environmentalists, low income advocates, industrial customer groups–the regulators often discount what each says due to their history of proposing items of self-interest. How these disparate groups can come together is a potential solution–but it may not be easy. To me, regulation, is maybe the biggest risk to the utilities because customers, like what John was describing earlier, can end up solving these programs and disintermediating the utilities all together.

Barone: To me this is a very interesting situation for Hawaiian Electric, I'm sure it exists in other jurisdictions. We've got a commission that's really pushing transformation and pushing innovation. But I think the challenging part is that... If you want to look at, there's really three reforms that need to happen to get us into the future. There's rate reform. There's utility business model reform. The one that doesn't get addressed well enough is regulatory reform. Because just as utilities are seen as being very slow to move and maybe risk averse and so forth, the regulatory process, at least as I have experienced it, it's really only being directly for just about five years that I've been at a utility, before that I was outside looking in, it doesn't lend itself to the same degree alacrity that we're being asked to act with.

So that's the regulatory reform part. I don't have good answers for that, but I do see that this is a gap in helping this transformation happen. But I'll speak very quickly to the rate reform as well as the business model reform. I'll start with the business model reform. As many of you are probably aware, and seeing in different jurisdictions, we at Hawaiian Electric are being charged to make fewer and fewer capital investments. And that's fine, let the market speak, let's get the best prices for these services and assets, that's wonderful. Except, it's in direct or contradiction with the standard and conventional utility business model, as to how we make our money, if you will, and get recovery and returns is making capital investments.

This notion of PBR or performance-based regulation or performance-based rates, is a mechanism normally manifest... And you've seen and read it in other jurisdictions as a shared savings model, that's one version. But it does provide an incentive for the utility to go and make alternative investments i.e., "Hey, let's aggregate a bunch of distributed energy resources for providing the services that our transformers might have otherwise done in a non-wires alternative, for example. Well, if we can–as the utility–do this in a cost-effective way and then enjoy a portion of the savings in lieu of getting our returns on the capital investment of those transformers, that should be best for everybody. It allows us to modify our business model and still be made whole and maybe even better than whole from the capital investment we otherwise would have made. So PBR is an important cog in this overall reform.

And then rate reform. Jenny you pointed out, "What do you pay customers?" The other thing is when you're dealing with load defection, if you will, there's elements to how do you capture your fixed cost for managing this system if it's not directly tied into the kWh sale. We've been struggling with this. There are lots of different ways to... And I'll just quickly, if you'll allow the indulgence, sprinkle in something we've been just working with as Hawaiian Electric, just formulating so it's unofficial but I wanted to share the general concept. It's working with DER aggregators to develop a piloted rate structure. We have a certain allocation of fixed cost–you might call that your minimum bill portion. On top of that we're looking at just saying, "Based on annual usage, we're going to give each customer a kWh block per month that they'll have access to for a certain dollar amount. If you go over that, there's a sales charge, you might have to pay for additional charges."

"Now in exchange for that, that's your base rate, and if you've got assets that you can commit to being available to the utility and at the utility's discretion, there be a rebate on a per kW basis for availability. That asset or those assets are at the discretion and control of the utility." In this context you can provide bill certainty to customers and provide the utility with the control of the assets to use flexibly at their discretion, that could be energy, could be capacity, it could be ancillary services. So we're just now starting to look at the economics of how this might work, how the controls might work and how the performance assessment might work, as a means of moving forward into different rate reforms that get us to this degree of operational flexibility with customer assets.

Louisa Freeman: Louisa Freeman, DNVGL and we're speaking later with Tracy Schmidt from Tennessee Valley Authority about aggregated demand response. I'm wondering, back in the day utilities used to have some ownership, either of water heaters, or they would lease things. Is there a play here on ownership? A lot of distributed energy resources energies coming on are utilities looking at different models of, "Do we own the asset or are we leasing the rooftop for the solar panels?" Those kinds of things. As part of that incentivizing the customer concept, is anybody looking at different ownership of the technology models?

Phillip: I can say as Duke we definitely are looking at those types of things. I think looking globally more at energy as a service period and how you participate in different ways that take the burden of ownership of that type of equipment off of customers. And that's up and down the food chain, not just residential water heaters, not just big commercial chillers but playing the space in between as well is definitely on our radar screen.

Timing's always an interesting thing. How it all fits together. How it fits with regulatory rules. Do we use solutions developed from the non-regulated side of the fence versus regulated inside the fence? Those are all things that we can wrap ourselves up and get confounded over. Are we looking? Yes! We're not short on smart people. We actually have that, but as a large, regulated company, getting out of our own way in order to go and develop a culture that failing is part of the deal is where our next hurdles lie. But absolutely, I think that asset ownership needs to be part of that solution.

Brown: Under our current regulatory model, which has not really been reformed, he ownership, they're looking at that. We've just done a lot of renewable PPAs (power purchase agreements), a 1000 MW, another 1000 MW of renewable PPAs coming online, 300 megawatts of storage in the first round, another 4 to 500 MW of storage coming. Of course, our execs would love to figure out how to own those assets. Everything's been coming through PPAs. Highly interested in figuring out a business model around storage and how to own the storage asset projecting access renewables and how do you absorb that.

They're forming teams to figure out what business models and services would look like and where might we put storage, and so using the publication, NWA case studies that we released the last time and we're having those conversations about the value of storage and trying to figure out how to locate it at the grid edge or at substations or behind the meters. It's absolutely a big thing.

Barone: Unlike Duke Energy we are a small confused company, not a big one. A lot of themes here. Look, for many years... Look, there are exceptions out there where utilities do own assets behind the meter but from where we sit there's been this force field at the meter, and we don't usually reach into there. I wouldn't say we're looking at the opportunities, especially on the distributed side, but we're certainly thinking about where those opportunities might be, what's going to be the regulatory appetite for this. But if you look at the three stratum, there's the purely customer-sited assets and we would certainly love to understand a model where we can own and operate assets and figure out a way to make customers whole for that transaction.

Then there's microgrids, we've just had a microgrid docket opened up. So that's an open docket. Can't say much about it except that within question is, what is the latitude for ownership models of microgrids and is the utility in that mix? The third tier would be, as Michael has alluded to. We're about to go into our second wave of PV, PV plus storage, and standalone storage RFPs. Hundreds of megawatts. In this recent RFP we have a self-build option that's been afforded us by our commission. Maybe starting at the macro-level we can work our way down system, but we are now permitted to, within a certain code of conduct and within a competitive framework, as a company and we'd have to carve out a team of people that were firewalled off from the rest of the company. We are going to be permitted if we so desire, to put in a bid for a self-build asset that would look like an IPP to the utility.

So, there's been some movement at that level, and we'll see if we can evolve our way. We have an interest, but we just don't have anything formative at this point.

Roehm: From the outside looking in and seeing what's going on with the utilities, there's this weird push and pull where utilities don't want to own the assets so they're really pushing everything out to be, "Let me just buy this service. I'm either buying capacity, energy, or whatever", they are contracting for whatever it is." But then there's also the control freak side of utilities that really wants to own the asset so they can make all of the decisions around it. I think the pendulum is swinging more toward "I'm going to buy it. We'll just buy the service from either the owner, from the end user or from somebody who goes and aggregates that particular type of asset, all the storages, all of the ACs, whatever the asset class is."

Tyler Rogers: Tyler Rogers from EnergyHub. As we look at the future of DERs, I'm curious from the panel of how far will we go in flipping the grid on its head, of taking the power plant, remove from everyone and putting on top of roofs? How far will we go into the future of DERs being the prime source of generation? Where does it actually stop and say, "We've found this balance."?

Brown: Well, that seems like a stretch for us, at least our particular situation with the portfolio standard. Our legislature just recently, last month, passed a 50% renewables by 2030 requirement. We expect to be there in the 2023 time-frame and we fully been expecting them to raise that portfolio level even quicker. So, at the speed at which we're trying to achieve the portfolio standards, the desert outside Las Vegas is going to be filled with solar panels and it's rapidly filling up quickly to meet these mandates. So, to be fully powered in our territory with behind-the-meter solar, I think that could be a long way. But at the same time, we're certainly looking at all sort of ways to leverage behind the meter solar, in particular smart inverters, to help us with distribution and grid management, right, active grid management. We do believe if there's opportunity there we're exploring it and absolutely don't want to discourage that, now that we're looking at those opportunities through that new lens for distribution grid support and management.

Powers: To me that should be an economic question, right, to the extent that deployment of distributed energy resources behind the meter is something that customers want, customers are willing to pay for. Utility can take the grid and take the power one way or the other. If the customers want to pay for it behind the meter is going to win. If it's a simple where is it cheaper to deploy some renewable resources, of course, it will be in the desert outside of Las Vegas at great scale. Yeah, so definitely my roof is a less good place to make energy than the desert outside of Las Vegas and yet I put solar on my roof because I wanted it, because I wanted a sense of control and to be able to move on that decision when I wanted to, not when the utility wanted to. So, I think it's an economic question and we have to be prepared for customers to want to deploy way more of these things very soon.

Roehm: Think about everybody in the community having to have some sort of distributed resource, you're always going to have to have some sort of centralized generation to make it all work. The things that would have to happen, we would have to no longer have the connected grid that we have and the ability to move power from all places that we do. I used to work for BPA in Oregon. Power moved on a regular basis from Canada to California. We would have to break all of that infrastructure apart and create it in such a way that people can still go to the light switch, turn it on and have lights. I don't think it'll ever happen. Is it going to be different than it is now? Yes, but it'll never be there.

Barone: I can answer for Hawaii with a real number. So, our power supply improvement plan, which came out maybe a year and a half ago and that's our blueprint for the next 30 years, gets us to 100% renewables, and calls for about 50% of the capacity to come from customer-sited assets. In our case, it's not strictly economics, to John's point, that's a huge part of it. We have space constraints and we have system security constraints. There are real things, primary frequency response, inertia, or response that you do rely on larger spinning metal objects to help keep the system secure especially in a lower inertia system. So, we got certain parameters and constraints, but our number is looking at about a 50% target.

And so to chime in, I think reality falls some place in the middle, that there's a lot of things about running a grid that, for what I can see, which isn't forever, okay, but for what I can see they'll be some need for some central station to keep the grid stable. It's less from a percentage standpoint, dramatically less than what we're used to by far, but it might be... I don't have any grandkids yet but it's probably more towards later in their lifetimes that we'll be talking about would somebody be decommissioning the last central station.

Brown: In two minutes, if you could pick one thing that you think you need that would help to spur increased adoption of DER, right as we're moving forward into the future, what would that be?

Phillip: I'm going to set up my friend Rich again. Those of us coming from the DR space are used to talking about these things in one way, with one set of terms, in one perspective, and are seeing within the rest of the company differently. I run the island of misfit toys within Duke Energy at some level. They're not used to what I do. And to try to go work with the rest of the company that's trying to get after these DR assets has got a fair number of hurdles, internally and externally. Rich, do you want to build on that?

Barone: Yeah, I think those who've gotten to know me over the years know that we try to take a service centric approach to this stuff and not a technology centric approach to this stuff. Taking a technology specific approach to this situation in which we find ourselves creates, I think, distinctions that are false flags. Working within a culture of utility and a regulated environment, DER versus DR versus storage versus EVs. Look, what we've done for years is manage customer-sited assets to create some degree of grid flexibility. It may have been simpler and getting more complex but the principles, the underlying technologies, remain the same and I think for me the big change would be, "Hey, let's look at demand response as the ability to effectively maneuver and manage this big basket of assets." It would make regulation a lot simpler. It would make company organizational structures simpler. So really that change of mindset would be helpful.

Powers: I'll just build on that and say that the biggest change is not technological. It is organizational and people have to get comfortable getting outside of what Paul Miles calls, our cylinders of excellence, which is to get out of the silo, talk to the people in other departments that have some domain over whether or not... or how fast this all takes off. Talk to your distribution planners, talk to everybody in the organization. That's been the key to success in more projects than any technology. It is not taking so narrow a view and talk to the rest of the team.

Presentation slides available at https://bit.ly/38zVP5S

Lessons from the Grid-Edge: Operationalizing a Customer Driven DSM Portfolio at Entergy

From 39th PLMA Conference

Dean Chuang
Entergy

Matt Croucher
Entergy

John Boudreaux
Entergy

Dean Chuang: This is my third PLMA with Entergy. And for those of you who met me at the 38th PLMA Conference in Coronado, you may remember me speaking passionately about the exciting "retail-regulated" business model that we as Rayford Smith's team were trying to build. By Austin, I think I described myself at ULME as 'shell-shocked and beginning to suffer from PTSD,' trying to survive the challenges of doing this at a very traditional, very regulated utility. As Ruth said, I come from a retail energy background, so the culture shock was real. So now 18 months later, the world is still a little bit hazy, but the dust is starting to settle, and we appreciate the opportunity to share a little bit more about what we've been working on.

First a quick introduction to Entergy. We are a large, vertically integrated investor-owned utility with five operating companies in four states. We're a large nuclear operator, and we also have a moderately sized natural gas business in Louisiana. I'm going to pause for a moment here. This is the summary data that you'll see in any utility presentation across America. But from a customer perspective, these aren't the metrics that we really need to focus on. From the customer perspective, Entergy's three million customers are primarily rural and low income with two large population centers around Houston and New Orleans. And then from a system perspective, these customers mean that we have very long feeders in a region that is subject to extreme weather in the form of hurricanes and tornadoes.

And finally, from a load perspective we have a large base of heavy industrials. Petrochemical load is approximately 70% of our base in Louisiana. This customer focus is important because we believe that the future business model for DSM will be driven by customer value and customer engagement to deliver utility value. I'll repeat this a few times through the course of this presentation, but we've made the argument that proven customer-sited resources should be treated equivalently to traditional investments in transmission, distribution, and generation. It sounds like I should have read the white papers that PLMA put out last year, but we've taken the argument towards PBR a little bit further; we already have LCFC in a few of our operating companies and we are now asking for full capitalization of our DSM investments. To paint this picture, let me take a step back and review the concept of utility franchise. We as utilities exist because we have a natural monopoly on the operation of our systems as defined by the traditional transmission, distribution and generation domains.

Our poles, wires and plants exist to serve a certain service territory. And that service territory has a defined set of customers. We as a utility are allowed to charge these customers "just and reasonable rates" in the provision of a regulatory defined level of service throughout that system. This utility natural monopoly also implies a franchise to our customers that are serviced by our system, and we as utilities are allowed to offer demand-side management programs to the extent that these offerings also deliver system benefits. Again, these are benefits as defined and approved by our regulators. This construct is why all of us are in this room today – we are allowed to offer products to our customers because we and our regulators agree that these products will have a certain impact on the system that we're responsible for managing. Now this is why we're really in this room using PLMA's framework from DR 1.0 to 3.0, we think of everything on the demand side as having a place in a spectrum of utility value.

This includes everything from EE all the way into DERs. As an aside, Richard Barone with HECO spoke at the board meeting last night about the importance of aligning DR and DER with your executives and stakeholders. We absolutely agree. We have the benefit of dealing with a clean slate rather than dealing with the situation of imminent need that they have in Hawaii. But we've been working to align our stakeholders with this framework, and we believe that the right strategy will come from this alignment. From our perspective, all capacity has value and it's our job as demand-side management practitioners to determine which capacity is cost effective, and to develop a strategy to dispatch or engage that capacity for utility purposes. The DER strategy that follows from this philosophy is that DSM is a series of incrementally valuable resource silos.

On the left, EE and DERs that are not dispatchable deliver locational load shaping. And as we move into DR 1.0, we gain the ability to peak shave, while at 2.0, we have an aggregation that we can dispatch against economic signals. Finally, on the right, in the DER 3.0 world, we have an operational grid edge asset that can be dispatched in a real time for locational and system benefits. I know this is an eye chart, but underneath the resource silos we've listed KPIs, or key performance indicators, as metrics to track with each progressive stage of operationalization. For the purpose of this presentation, the details aren't important, but the progression that you see is a progression from regulatory compliance and basic customer satisfaction on the left, all the way to ancillary services targeted towards the co-optimization of utility and customer value streams on the left. We have defined utility value streams as benefits in the transmission, distribution and generation domains and customer values as driven by economics and customer satisfaction.

The takeaway is that if you believe that DSM can and should be developed as an operational asset, then the world of compliance programs is turned upside down. To reiterate, we're making the argument that prudent investment in DSM should be capitalized and treated on equal footing with traditional infrastructure development. Our argument is that if you believe that DSM can deliver the values in the DER/DR 3.0 world, and that we can statistically validate that DSM is delivering against these value streams in the real world, then your demand side management portfolio is delivering equal value to a new feeder, a cap bank, a line or a plant, and should be treated equivalently. This argument drives a number of business considerations. First, as an operational customer driven portfolio, customer enrollment is maximized to the extent to which it remains cost effective. This is very different from a regulatory compliance world of programs managed towards cost certainty. We're pushing for uncapped enrollment and, ideally, contemporaneous recovery.

Additionally, cost-effectiveness is improved with platforms that are scalable in response to either customer demand or costs, across resource silos. This means that (eventually, we still have some work to do) we will be pushing for portfolio level cost-effectiveness rather than program consideration. Basically, the business model shift that is required to operationalize the customer is also mirrored by a paradigm shift in traditional resource planning and operations. Where system needs were once met by ramping a small group of centrally planned and sited assets, operations are now driven by a distributed, grid edge portfolio of assets that can be aggregated and called upon to deliver different locational grid services.

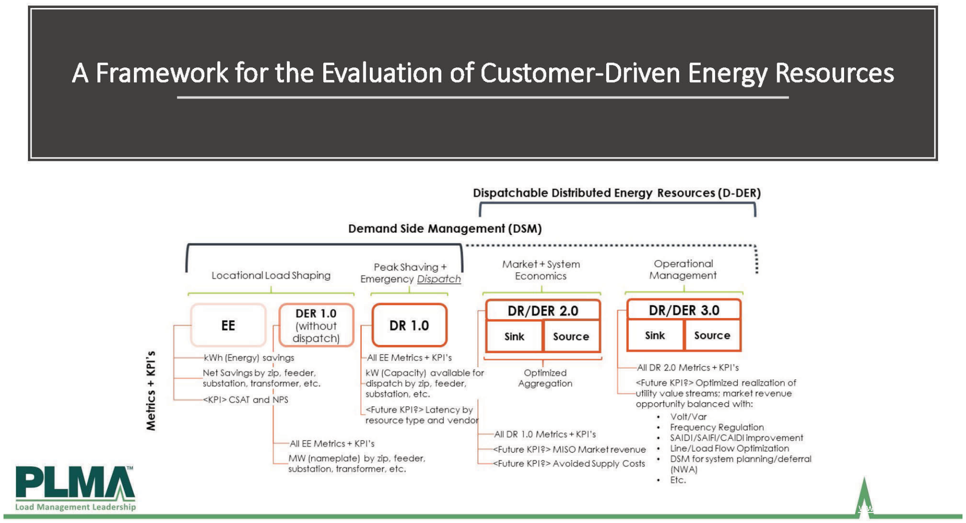
Most importantly, the fundamental operational shift is that the scale and availability of demand-side assets is driven by customer interest and customer satisfaction. What this means is, if you fail to engage your customers with a compelling message, then your DSM portfolio will never scale to its potential. And once customers have been engaged, if you fail to maintain a positive customer experience within your program, if you treat them as an end point rather than as a customer, then the performance and availability of your resource will decline. To tie this all together, our plan to operationalize the customer is designed around the retail concepts of the customer life cycle. Within the requirements of our regulatory construct, we're designing and defining the processes and systems to manage customer experience at different phases of a life cycle against traditional retail metrics like customer satisfaction, or C-SAT, and NPS, or net promoter score.

As a regulated utility however, the life cycle starts with ideation and foundational research to determine the right product for our customers and our regulators. And with that I'll pass the baton over to Dr. Matt Croucher to speak a little bit about some of the custom analytics we've done in support of our filings.

Dr. Matt Croucher: I'll just talk a little bit about the space. One of the things that my team are focused on, and I'm sure every utility is grappling with this, and it's something I talk a lot with my team and a lot around is "are the barbarians at the gate or not at the gate?" Are they at the door in the next two years, or in the next five years? When we think about the adoption of these customer driven resources, the focus of my team is to think about -just how big is the potential market? Here we've used the typical... I'll call this "potential study" sort of view of the world, right? You start with your total customer base, you bring in a technical potential sort of thing - does the technology work or not? You then identify some cost-effectiveness modeling (something that we're bringing internally into our organization as well) to run those cost effectiveness studies to bring agility to the programs that Dean and folks are looking at.

And then magically you normally slice off a part of that, and then you've got this addressable market. And this is where you make those big announcements of, "I've got a thousand megawatts of demand response just sitting out there." And then what you have to do is you have to then make sure that your load forecasting team are aware of it, your resource planning are aware of it, because you've got this resources being sited at a customer's house, customer's location. You've basically come up with the size of the market. You say this is cost effectiveness on the multiple different sort of programs and things that we're trying to look at, but then the key thing is - what's that forecasted adoption? Okay. As we think about all of the work that Dean and company have to do with when we scale, we have to identify what are we looking at? What is the speed at which we're going to adopt?

And this is my third utility as you heard in the introduction. I can tell you at each utility we always been two years behind in terms of the adoption. We think we might control the market. We might control it through our DSM programs. But, generally we don't. There's a lot of things happening outside of our industry that is kind of attacking us to some degree and then how do we pawn it to make those markets. So, this should be pretty well known to most folks. What we focused on here is the forecasted adoption, but also, we wanted to wrap some governance around this. One of the things that we identified at Entergy is we've got



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multiple forecasts in multiple different parts of our organization for the same product.

Demand response products, electric vehicles, solar. We got 10, 20, 30 different forecast opinions out there. So what we try to do is wrap our heads around this from a governance point of view of again going back to that simple question of "are the barbarians at the gate now," are they already in eating our lunch, or are they five, 10 years out? So that's kind of the focus as we think about the analytics. And really this is really a data science project matched with the whole argument around customer analytics. So, this is pretty straightforward. If I look at most people's adoption curves or outcomes, that magic S curve, I'm not here to explain propensity modeling and bass diffusion. I'm happy to do that at the break, but this is some of the things that we have to deal with. As we look into the research, as we look at the adoption curves, we have to figure out what is the speed of adoption? Because that's going to have an impact on all the things Dean is talking about.

How fast do we have to scale customer adoption? I'll talk a little bit later on about the interconnection challenges and how we scale as an organization to continue to meet the needs of our customers. Every time we do the customer research, what does it come back to? I want convenience and control. I want to plug something in and be told that that's okay. We're not going to come back. John's not going to come back saying, "I'm only joking. You can't do that." From a distribution point of view. So, the first focus is how much and the speed at which we're going to get there. And in an old life I would hand that over to the load forecasting group and they'd say, "Great, we're going to go and do the value proposition of clipping the system peak."

We all know the avoided cost calculations and the analytics that go behind the scenes, but we wanted to take it one step further than this. And the one step further I want to take you to is go to the distribution folks and say, "Where is it going to pop up?" A lot of the geospatial work is very new to the utility industry, and in order to have a geospatial view, you've got to have a lot of your customer information. We generally know things are going to cluster, just because people tend to cluster. But that's going to be important for when we think about the value proposition that we're going to talk about driving down. So the key thing for us, what we wanted to do is we did a lot of surveys in our territory, we brought that together with some third party information and we built likelihood models. Yeah, likelihood to adopt with surveys and things and then we expanded that out to the population.

So, really what we did is, we took that addressable market and we mapped it out from a geographical point of view. It's one of the first times that we're actually tallying leaders where it's going to occur in our territory. And as you develop and design different programs, this is going to migrate and move. And depending upon the resource, the migration is going to look different. I spent too much time at conferences, people talking about I want to match energy efficiency with demand response, with solar, with electric vehicle. That's going to be the greatest co-optimization problem in the world that you're probably solving for, for the 10 engineers at your company who love all this stuff. Most customers it's kind of going to be solar and maybe electric vehicle, or most customers it might just be a demand response product that they're interested in. Convenience and control. We talk a lot about the growth in the programs around thermostats.

So, what this has enabled us to do is identify the adoption of the customers and then map it to that area where it then feeds into a lot of what John and team are looking at, which is where it's going to occur. And I think one of the evolutions as we think about this and one of the conversations, and we were just talking about it before, is as we think about those added value propositions, as we move into or away from our call at the traditional cost effectiveness modeling, which is clip the peak avoided energy, you've got the kind of the generation benefits and maybe some transmission benefits–could be financial, depending upon the territory you're in. We want to then look into what are the distribution benefits. Or we want to look at if all this stuff coming and we're just not ready. And from a deployment point of view. So, with that, I'll turn it over to John.

John Bodreau: As Matt said, we are here on the engineering side. First of all do we have any engineers here in the room? One, that's about what we saw in the workshop. All right, great. Everyone else, I know we're just coming back from break, but this is a good time to check your emails or do whatever else you need to do. Dean gave a great background of our customer profile, our DER profile, our penetration levels. We have about a hundred megawatts of DER in our system and that's scattered throughout 19,000 interconnections across the four states and five OpCos. However, 12 to 14,000 of those interconnections are in the City of New Orleans. So, we don't see a lot of high penetration elsewhere throughout our system, but we do have it in New Orleans.

What we're looking at here, this is the customer engagement or the customer life cycle, and I wanted to note here that engineering fits into all of this, throughout the entire process. What our group is doing, is looking into how and where throughout this process, there's the customer experience, what goes on behind the scenes at the utility and how does this move through from standards, to planning, to field engineering, to implementation. Whether it's enrolling customers, looking at interconnection studies performed by standards, design engineering, what upgrades need to be made out in the field to improve hosting capacity to allow more programs. Or maybe looking into these as NWA, non-wires alternative solutions, and giving our distribution planners a new tool in their toolbox moving forward.

From the operation side, field engineering and sharing power quality. The last thing we want is to install a bunch of devices that are going to cause our customers' lights to flicker. DOC and TOC, distribution operations, transmission operations in steering and understanding that the presence of these devices are out in the field. And AMI might've given a better understanding of the behavior of these technologies. And lastly on enrollment. What happens when we lose X number of customers? What does that look like to our feeder now? Do system upgrades need to be made when all of those resources that were at the tail end of a feeder now want to unenroll? Kind of a contingency planning.

So, what we're looking at on two ends is the foundational process for designing standards, the interconnection process, the technical standards and specifications. One thing our group is looking into is how do we bring DERs from cradle to grave. When a customer approaches us and says, "I want to interconnect." What's that process look like from interconnection or from technical specifications, to procurement, to implementation, to operation, and then finally to decommissioning. Our group is looking into what groups come in at what point – when does planning get involved? When do standards get involved? And what those processes look like? And what those studies look like as well. So ,we use Synergy Electric in our utility, that's our primary distribution engineering tool to handle load flows, short circuit studies, et cetera.

But now, Matt hands off the baton to us with predicted or forecasted adoption rates on a by feeder level. So, we can take those forecasted adoption rates, we can implement load shapes to them and see how those new load shapes under given scenarios, be it low, medium, high adoption rates, what does that do to the feeder? What's the feeder's behaviors? Is it a rural feeder? Is it an urban feeder? What system upgrades need to be made? This is how we're doing these studies right now. How does it impact the load shape, capital deferment, T&D upgrade deferral? Things like that are being done right now by these studies.

New tools and analytics were mentioned. So, we're looking at tools like LoadSEER to better understand bottom-up forecasting based on these new adoptions or various scenarios of adoption. What does that look like? Aggregated up the feeder to the transformer. Is that overload that we are predicting going to be there in case of the adoption of this many demand response programs or new DERs that can defer these upgrades? Additionally, we can take those new load shapes from LoadSEER and utilize those in Synergy to better understand the engineering impacts. What does that do to our new load flows? What does that do to short circuit studies? What are these new technologies? How do they impact our distribution feeder? And that was my short slide, Dean limited me to four because there were three engineers in here, so...

Chuang: That's slanderous Mr. Boudreau. So, what are we actually doing in DR? The business model we described has been filed in New Orleans and Mississippi, but to take us full circle to my opening remarks, unfortunately we're still working on stakeholder alignment across the enterprise. On that note, the stuff that we've been given permission to publicly share is right here. Prior to filing a more detailed IRP, we've been advised by our counsel to limit the conversation to philosophy. So bear with me a little bit...but philosophically, the offerings that we filed and recommended to leadership are pilots which establish the value of a mass market customer engagement program; our goal is to meet customers where they are, not where we as utilities want them to be.

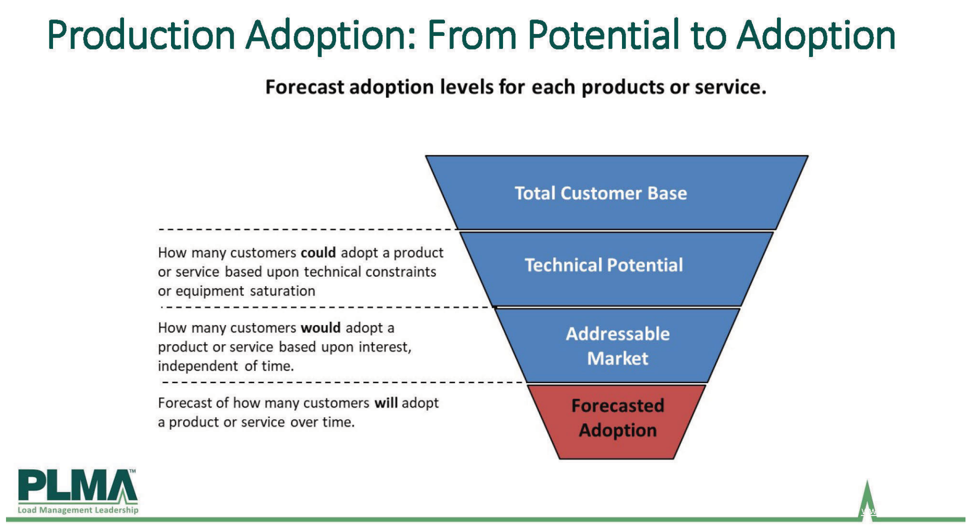
And from my perspective, which we will confirm through surveys and ethnographic research, "where customers are" is IoT or the internet of things. So, from my perspective, we start with thermostats, but in the long-term, I want any connected dispatchable load as part of our system as a registered system asset. A similar philosophy guides our approach towards C&I. Our goal again is to align and to develop a mass market C&I program. The key here is standardization. Recognizing that every industrial load is different. We're looking to identify standard control points and develop processes that we can replicate across sites, customers, and ideally industries. That said, we recognize that many industrials are going to require custom development or customer engagement. And we still need to run these pilots and determine our own internal economics, but my hypothesis right now is that many of these loads will probably be better served and more cost effectively managed through aggregators.

Finally, to sum everything up, what we've been trying to do is develop a retail engagement model within the construct of our traditional, regulated utility. This is our interpretation of what it means to be customer first and customer driven. That said, I'm looking out right now at a room full of successful industry practitioners. So, this is very clearly not the only model. However, if you're looking to integrate DERs, if you're looking for a new revenue framework, or if you're looking to engage a commission that hasn't focused on DSM, this might be something for you to consider. Just recognize that this path that will touch every aspect of your utility and be prepared for what we've been calling "aggressive alignment" and proactive engagement.

J.T. Thompson: Gentlemen, you mentioned that it's a paradigm shift that we're seeing and it was a great slide of showing where we are versus where we're going. A few questions along that. What is driving this shift, what will accelerate it, and what are the barriers that you foresee kind of maybe prohibiting that shift from taking place?

Croucher: I think we're on this evolution. I mentioned earlier, I run the analytics practice, so every time I hear a leader say we're going to be data-driven customer-centric, they then stare at me to say, "How are you going to make that happen?" And I think this is just one of a portfolio of how we're trying to think through that customer-centric sort of view. And if you think about the first few slides that we show, really you could stamp risk, risk, risk, risk, risk across all five of them. We're changing the mindset on the evolution of this is messy, it involves customers. We've got to think about convenience and control. Why don't we just build a power plant? We know those, we've been doing this for the last 60 years. And I think what we're seeing is first of all, this conversation is changing from what we want to what customers want. We're a very low rate utility, we've been very focused on meeting the need from a pure operational point of view, but the leaders are seeing this change to this customer focused and customer driven view, of which a key part of it is everything that we're talking about here. And I think our leaders are starting to realize as you think about rate cases and what you want to do in other areas, it's kind of like, what are you doing for the customers outside of just, "We're trying to keep rates as low as possible"?

Chuang: One focus I would also say has been we recently, about two or three years ago, we started kicking off a grid modernization project. So we, as many utilities have a tendency to do, we focus on products. "So we want this, we want this, we want this." And I think we're starting to catch up on the why behind grid modernization and the why to develop on Matt's point that is resonated leadership has been customer engagement and customer first. So now we're trying to figure out how we actually execute against that strategy and how we do that.



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Bodreau: I think from the engineering side, the paradigm shift is largely driven by the technology and these new technologies coming online, that we need to be able to better utilize the tools that we already have in our toolbox. Everything from a software perspective, better utilizing our engineering software, bringing new tools on like we're doing with LoadSEER, as well as being able to understand how these new devices can be used for our benefit. I think that that's probably the biggest, it's the education of the new technologies.

Thompson: Matt mentioned this being very much a customer centric or utility customer-relationship driven type of approach just a second ago. And this is a bit of a loaded question, but is this as much work on change management within the utility as a whole, when you've got five OpCoes versus the holding company and how that shakes out? Is it much an exercise in change management as it is kind of do customer centric or customer driven programs?

Croucher: I think the answer is yes. I mean we're trying to have a corporate strategy around the customer. Each of our operating companies are at a different point on this path. If you talk to a couple of them, cost effectiveness modeling and their maturity of what they're doing in their operating company are a lot further than in other areas. But we're really five small- to medium sized operating companies. So how do we deal with the change management? How do we get our arms around the governance of all this? Dean mentioned AMI and smart grid and the projects run that. We are very siloed within that, so how do we take all this up to a higher level, and drive that customer centric sort of behavior? And we see that this being a key engagement strategy.

I spend a lot of time talking with the other groups involved in our utility around cost to serve. And it's the 80-20 problem, right? 80% of your cost to serve come from 20% of your customers. So, then every so often I'm the antagonist in the room. I say, "What are we doing for the other 80%?" The other 80% that when we survey them, or we do net promoter score, they just shrug their shoulders. So it goes back to them, "What are we doing in this space for the DER, the energy efficiency demand response, which then quickly becomes, we need to bring this up to a more corporate sort of strategy and take all the lessons learned from our operating companies. It's not like they've been doing things wrong, but really it's come from a regulatory push as much as it's come from a customer kind of centric view.

Chuang: I will say that, particularly recently, there's been a desire to begin exploring to Matt's previous point about are the barbarians at the gate? There is a definite push at Entergy right now to begin exploring below the line revenue and begin exploring opportunities to engage outside of our traditional utility domain. And in order to do that, a lot of that drives from, at the end of the day we are a utility, how can we engage customers through our platform and what's the best customer model as well as regulatory model through which to pursue this? And again, to bring this back to Matt's point, a lot of this loops back to our operating companies, the regulatory positions we've established across our operating companies to your point, to J.T need to be aligned. We have taken different positions on capacity values, we've taken different positions on customer values. And all of this is in the process of "aggressive alignment."

Thompson: How much does the regulatory piece of this factor in, and how much of it is reeducation, how much of it is just... We all have dealt with regulators in our own spare time, I guess, and we have our opinions of them, good, bad or indifferent. But how does it play with what you're trying to do and what role are they playing?

Chuang: So far, we've gotten pushback from intervenors in New Orleans. Mississippi seems to be moving fairly smoothly. So just background–we filed this business model in Mississippi and New Orleans so far, we're still working on some overall enterprise alignment. We are a regulated utility and we respond to our regulators. But that said, I think a common thread across all of the DER conversations has been that there needs to be a certain degree of regulatory engagement. Regulators don't quite understand. I think Rich had a great comment before. Regulators know how to operate the utility of the 20th century and where we've advanced into the grid edge, it is our belief that that education is going to unlock our future utility business value. That said, to tie this into the comments that Rich was making last night, I personally think a lot of that engagement has to happen in NARUC.

We respond to what the regulators say. Our regulators occasionally ask us to do things that are contradictory. So, as we begin trying to build a business off of this, we need to make sure that everyone is aligned on the same perspective and same view was to grid values and where the future is going.

Croucher: One of the conversations we have a lot of times when we talk to the regulators is we focus on the technology. And a lot of our leaders will say, "We've got a lot of smart people like John. I'm not worried about the technology working, because you'll make it work, right?" We've got a lot of engineers who can make things work. That's what they do. But it's really having the conversation with the regulators saying, "This isn't what Entergy wants, but this is what our customers want. So, change of story, we have a lot of the research and a lot of the things that we're trying to do and say, "This is what the customers are requesting and asking for."

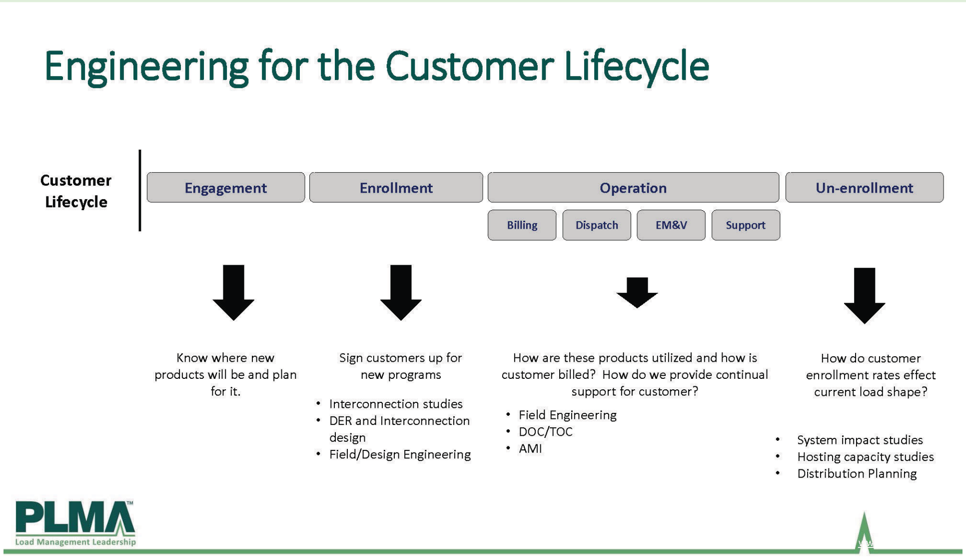
We're trying to fill the void. If we don't fill the void, other people are going to fill the void on our behalf, may lead to an erosion of their "power" to some degree. But it really comes from not making this conversation around we want to do this technology because it's cool and because we could rate-base it potentially, but because customers are requiring and asking for it. So how do we meet them there to deliver the products or services that our customers are asking for?

Bodreau: I want to revisit the change management question real quick. I think engineering probably has the toughest job when it comes to that. The past hundred and some odd years distribution flows have been one way. And now we're looking into or seeing a lot of bi-directional load flows. If you would have asked the distribution planner 10 years ago, "What's your minimum loading on that feeder?" They would've looked at you like you were crazy. Historically, we've always planned around peak, so it goes back to the new studies that need to be taught to planners, the new tools, the new technologies. So I would say from change management, I probably have a harder time than these guys.

Steve Wheat: Steve Wheat from Sunrun, otherwise known as one of the barbarians. I'm curious, you guys touched on it, but where do you see the role of aggregators as you start moving past kind of the citizens of New Orleans and into the other parts of your territory and bridging the gap between both customer understanding of these resources and responding to that demand that's more difficult from a centralized utility standpoint.

Chuang: If you look back at that that framework of EE all the way into DERs, our belief is that at the end of the day, an aggregator can only respond to a market signal, and that market signal is either coming from an ISO or balancing market or it's coming from the utility. And again, if you believe that spectrum of capacity, our belief at least is that a system that's connected to our systems, to our back office that is actively managed against our distribution values, transmission values, where we can prioritize the use cases we want to dispatch against, our belief is that aggregator should fit behind a utility program. That at least is the business model that I believe makes sense for a comprehensive DSM program.

John Thomas: Good morning. John Thomas with the Ground Source Heat Pump industry. Two questions. Interesting compelling thoughts on adoption rates and how do you approach different technologies to drive the change that you want? When you talk about the consumer satisfaction side of it, most consumers don't understand the topics that we're talking about in this room. Now, first part is what role does consumer education play in Entergy's plan to drive the change on the consumer side for DR, DER, et cetera? And then secondly, what role does HVAC play in Entergy strategy from an overall change management standpoint?



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Croucher: I'd say we've got a lot of lessons to learn on the customer education. We've got to do more of that. I will say it goes back to this. Every research is convenience and control, right? There's a level of information that they need. I think what we get into is we want to tell you all the bells and whistles of the technology and those things, but what we want to focus on is really, it's back to "what's in it for them"? As we think about the education, it's kind of like where is the value proposition? As an example, you talk about HVAC load. I spend a lot of time talking to our team. When we have customers who call to complain, the first thing we say is, "Well turn your thermostat up." We're not educating them about efficiency, smart thermostats, other technologies that are out there to lower their energy bill. Our traditional thing is if you want to lower your bill, sweat a little more.

And then we complain when they call later saying, "Why is my bill so high?" And we say, "Well it was hotter outside." And they say to us, "I never changed my thermostat setting, which is exactly what you told me controls my entire bill and not to worry about the outside temperature." So, I think we've got a lot of lessons learned from how we educate customers about what what are they using electricity on, their bill and those sorts of things. And we need to enhance and improve that as we think through the products or services that we're trying to offer to show them the opportunity. But I think one of the things that we're trying to focus on is what are the products or services first that we can offer you that have maybe lower impact where the customers don't have to do very much? And that goes from all of the conversations around enrollment.

So, for example, if we're asking you to fax us a document, we're probably doing something wrong from their whole point of view. And I say that as someone who had to fax something recently. Amusing, trying to find a fax machine. So, I think it's becoming critical that as we think through the portfolio, it ultimately comes without... Customers aren't going to adopt if they don't have a level of understanding. But how do we draw the line between the technology and what it can do and explaining it to them why we want to control these devices, for example, versus basically going back to what's in it for them? If you do this, you'll see this X saving on the bill. Sometimes that's as powerful a message as they want.

Chuang: I'll seize on Matt's last point of from my perspective, demand response is utility product. But what demand response as utility product does, it aligns the utility incentives with the customer incentives. So again, if you break demand response down, what demand response is it's a contract between the utility and the customer. Financially speaking, it's essentially a call option. And as that contract, that's a contract that can be executed either through a rate or it can be executed through a program and program Ts and Cs. And from a customer experience perspective, our goal is to design terms and conditions that are understandable, so customers understand what they're signing up for. And specifically, I think there's an importance in different tiers of residential standards and C&I standards. So commercial customers might respond to cost. A residential customer is really looking to make sure that, to Matt's point, we're not going to turn off the thermostat and make them really uncomfortable in the sweaty South.

What we've ended up designing and what we've ended up proposing is we've proposed residential terms and conditions that allow us to target the day ahead markets of long duration events, but really where we think this population is moving and where we think the future is moving is short events of 15 minute durations targeted towards HVAC load, which if we cycled between populations, we have less overall capacity for any given event. But there should be no noticeable impact for any customer on that program. So that's where we think the future's going as a balancing resource that becomes a resource that we can call in perpetuity, based on the terms of conditions that we're looking to establish with our customers. And to your earlier point this is the South, and HVAC is probably 65% of load everywhere. So we understand that. There was another slide before about economics and grid economics from a product side are different everywhere around the country. But in the South, it's heavily driven by HVAC.

Joseph Childs: Joseph Childs, Eaton. Going back to the distribution planning, you talked about the different load shapes and the calculations. My background with the IRPs is that they are done annually. Distribution load flows that go into those plans are done maybe quarterly. But as we talk about this rapid customer adoption of DERs, can you discuss how often do you think you're going to have to run studies on individual feeders and substations?

Bodreau: We've been trying to align these new studies with the distribution planning yearly cycle and where it fits in and how. This is such a rapid timeframe, right? Your distribution planning timeline was one to five years. Your T&D or your transmission timeline might be five to 10 and your generation could be some odd 20 years plus with that planning. This however, this could be monthly depending on how customers enroll. So, this is really forcing us to be more agile. To answer your question directly, it's something we're still playing around with. I think it should be run anywhere probably four times a year minimum because of these adoption rates and changes on the feeder that are rapidly taking place.

So one side of that modeling is accuracy, is determining where on feeders they are coming. But I think another very important part is being able to study the behavior overall, to understand this as a rural feeder and demand response programs X, Y, and Z have these load shapes with these impacts when they are primarily at the end of a feeder. So, that gives our planners a little bit better understanding of what the program's impacts will be. And additionally, using new studies, 576 or 8760 load flows, right? Our load flows are becoming much more dynamic. We're not just looking at a seasonal or a yearly peak. We're looking at a peak every month of a weekday and weekend profile. But to answer your direct question, I think anywhere four to six would probably be a good start.

Presentation slides available at https://bit.ly/2RmL14Y

Demand Response for Distribution System Management

From 39th PLMA Conference

Shira Horowitz
Con Edison

Jeff Haase: Our next session is going to be discussing demand response for distribution system management. We're all familiar with traditional demand response for peak load management. Con Edison has an experience using demand response to help manage the distribution grid and how this can be applied to a wider variety of distributed energy resources in the future. With us today is Shira Horowitz. Shira is currently the manager of demand response at Con Edison. Previously, she worked for PJM Interconnection and did research at Carnegie Mellon Electricity Industry Center. Shira spent a year in Sweden at the Royal Institute of Technology completing a Fulbright in sustainable power generation and working at Vattenfall Wind Power.

Shira Horowitz: I currently manage the demand response programs at ConEd, and right before that I was at PJM, so I have a little bit of experience on both the wholesale and the distribution side of the house. And I'm going to be talking about how we can use demand response for distribution system management, and I think what this really does is it sets the stage for how we can take a wider variety of distributed, dispatchable resources that go even beyond demand response and how we can use those to manage the distribution grid.

I'll just start with a quick overview of the ConEd system just to give you some context. We cover three commodities, electric, gas and steam. Our electric utility, our electric service covers all of New York City and Westchester County. We have three and a half million customers, which is over nine million people, and our peak load is over 13,000 megawatts just to give some context. So, I'm just going to give a brief overview of the ConEd distribution system. There's some little differences in how the ConEd system is designed that impact how we use our demand response programs.

The high end of this is the same for everybody. The power comes in either from generating stations or from interconnections, and it gets to us on transmission lines, right? That's the wholesale side of it. Once it gets to us, right, we step it down at a transmission substation. Most utilities, or many utilities, will step it down to distribution level there. We step it down to what we call sub-transmission, and then we send it out to our area substations. The area substations is where it gets stepped down to distribution level voltage, and some of our customers then get their power via radial feeders, which is how most people in this country get power.

But we have it that's a little different, is most of our customers actually get power from network systems, so what that means is we have a series of primary feeders that are all interconnected in parallel, right? And then that feeds a secondary grid, and our customers get power from there. What that means is I can lose multiple primary feeders without dropping any customers. All of our networks are designed to be, and mine is too, but in most situations, I can easily lose four feeders without running into trouble.

Now, what this does is it actually provides more opportunity for demand response for us, because I can lose a primary feeder, but I haven't lost customers on the other side of that feeder, so when I'm losing the feeder, all I'm losing is a little bit of capacity there, really. So, with all my feeders in service, maybe a certain network could handle 300 megawatts. Now I lost a feeder, and maybe I can only handle 295 because of that, and then I lose another one and I can only handle 280, so reducing load can actually help the system last longer, right? Because if I lose too many and I can't handle the load at that time, then we have to shut down the entire network and we lose all our customers, so it's kind of mostly more reliable. But also, higher stakes, because if we shut it down, we have to shut down everything.

Obviously demand response and these distributive resources are all located on the distribution side. With the exception of a few transmission customers that are out there. There are demand response programs on the wholesale side, right? So, many of the ISO's and RTO's are running demand response programs, so they're using these distribution-level resources to solve transmission-level problems. Typically, it's used for resource adequacy, right? So, that's usually something... It's capacity market resources, and it's trying to solve sort of some supply-demand imbalance. They're also used for economics, right? So, bid into the energy or insular service markets.

On the distribution side, we're basically using it for two things. One is to avoid distribution infrastructure, right, so we want to peak shave to avoid that infrastructure. And the second thing is it can be used for reliability purposes when we have contingencies. Many, maybe even most, utility DR programs are actually used for wholesale, to solve wholesale problems, right, so utilities are bidding it into the PJM market, or the NYISO market, or any of the other ISO markets. Or they may be triggering peak shaving off of the RTO peak, right, instead of peaking it off the distribution-level peaks. So, if you want to use it to manage a distribution system, you have to actually be shaving distribution peaks and sort of responding to distribution-level contingencies, which is what we'll be talking about here.

As I said, our system is divided into 84 different networks. Some of them are radial, some are networked. We call them all networks even though some of them are actually radials. And this is a little animation that's going to show us how they all peak throughout the day, so our system peak is actually at 5:00 PM, but you'll see here that some of our networks start peaking at 10:00 AM, and then some start peaking at 11:00 PM, so there's a really wide spread.

You'll see Lower Manhattan is going to start peaking out first, because that's very commercial networks, right, so the peak is driven by commercial needs. And then you'll start seeing Lower Manhattan and Downtown Brooklyn, which are all very highly commercial areas, and then you'll see some of the areas in Staten Island and Westchester that peak a little later in the day, or mixed commercial, residential areas that are... it's stuff that's really driven... The residential areas that are driven by central air conditioning, and then the mixed areas.

And then lastly, we'll start to see networks peak out in outer Brooklyn and Queens, the Bronx and Upper Manhattan, and that's where our load is really driven by window AC units, and those networks tend to peak late at night. And here we'll finish it off. You see things start to clear off at 10:00 or 11:00 at night. If we want to really be able to manage a distribution system, we can't call everything at the same time. I've got to call some of them at 11:00 AM and some of them go up to 11:00 PM.

I'll just give a quick overview of what our demand response programs look like and what our resources look like. Mostly, we are using our demand response resources to solve distribution problems, as I just mentioned, so that's peak shaving and contingency. We also, under very limited circumstances, we do call it for wholesale purposes, like when NYISO calls their resources in there. We're targeting system peak as opposed to the network peaks. We also have a gas DR. There's a tiny, little plug for my gas DR program. Ask me about it later. It's great.

Our biggest program is a performance-based program. By performance-based, I mean we're measuring reductions based on baselines and mirrored load. I don't care how you do it, I just want to see that you shave it. That's mostly C&I customers. Residential customers can participate as well, but it's a smaller number. And then we also have our mass market programs, which are all sort of different forms of DLC, so we have legacy direct install customers.

Mostly what we're pushing right now is BYOT. We also have a smart AC program, which is for customers who have window unit air conditioners since we have seven million window units in our service territory, so a little bit of a different... I have 680,000 central AC's and 7,000,000 window AC's, so different challenges. And then we have a bring-your-own-device, which is really focused right now on Wi-Fi-enabled air conditioners. We also have a couple of pilots here and there.

Then just to sort of go into a little more detail for how we use these programs. I'll talk about the peak shaving program first. We call all the networks on the same day for peak shaving, so all of our demand response resources on the same day, but we're calling them all at different times, so each network is assigned a call window based on when that network peaks, so starting at 11:00 AM, ending at 11:00 PM. I have about 330 megawatts of resources there, but I'll never see 330 megawatts at once, because I spread it out throughout the day.

Then in our contingency program, there I'm calling one network at a time, so you see in this graphic on the left side everything's blue, all my networks are doing great, and then we have one all the way in Lower Manhattan that's red, that one's having trouble, so I just call that one individually for their own localized contingency. Right, so I typically will call that when we have something, a contingency that results in us having to move into a voltage reduction. And sometimes we also call it before we go into a voltage reduction if I'm in a second contingency or a third contingency in a specific network. I'll talk a little bit more about that later.

This is a brief overview of who participates. High level, we have about 380 megawatts of resources, and that's over 13,000 megawatts peak, so it's 2% to 3% of our peak, and it's 25% generation. The rest of it is curtailment. And we do actually allow customers to export onto our grid for demand response purposes and get credit for that, and we have customers who do that. We can talk all we want about managing a distribution grid, but it doesn't matter. If we have no resources, it doesn't really make a difference.

This graph is showing the impact that we have, so this is just each bar represents a different network that I have in Manhattan, and it's showing the percentage of demand response I have in that network divided by the peak for that network. You can see in two of my networks I have about 8% of the peak. And then there are several other networks where I have over 4%, and then it kind of falls off after that.

There are some locations where you see those last few networks where I have under 1%, so yeah, if something happens, I don't know, maybe I can help. We'll try it, sure. But there are some, if something happens in a network where I have 8%, right, that's better than a voltage reduction. So, sort of long run, if these are resources that we can count on and we can forecast, we can avoid operational moves like voltage reductions and other operational moves, and that's really the goal of our contingency program.

Just a little bit of a summary of what are we doing today, practically what are we doing, and how does this impact how we manage the distribution grid? So, for our peak shaving program, in order for that to really matter, it has to be part of resource planning. We have network-level forecasts, right, so very localized forecasts, and that's what we design the grid based off of. And demand response is a line item in there, right, so we might have a particular network that, let's say, the forecast for next year is 300 megawatts, I have 10 megawatts in that network, we show that as 290 megawatts, right? And if the capacity of that network is 295, DR just essentially removed upgrades that needed to be done to that network.

And then on the contingency and the reliability side, right now, again, we call it generally speaking when we're in a voltage reduction. It didn't avoid a move, but it's helping us gather data that can potentially help that in the future, and maybe we run into a 5% voltage reduction, but who knows, maybe it's helping us avoid an 8% voltage reduction. And we also call it sometimes before voltage reductions, we are allowed to call it whenever we're two contingencies away from dropping load, which on a hot day is everywhere-ish. And we don't just call it. We wait until we have some contingencies, and once we have a second or a third contingency, we would call DR.

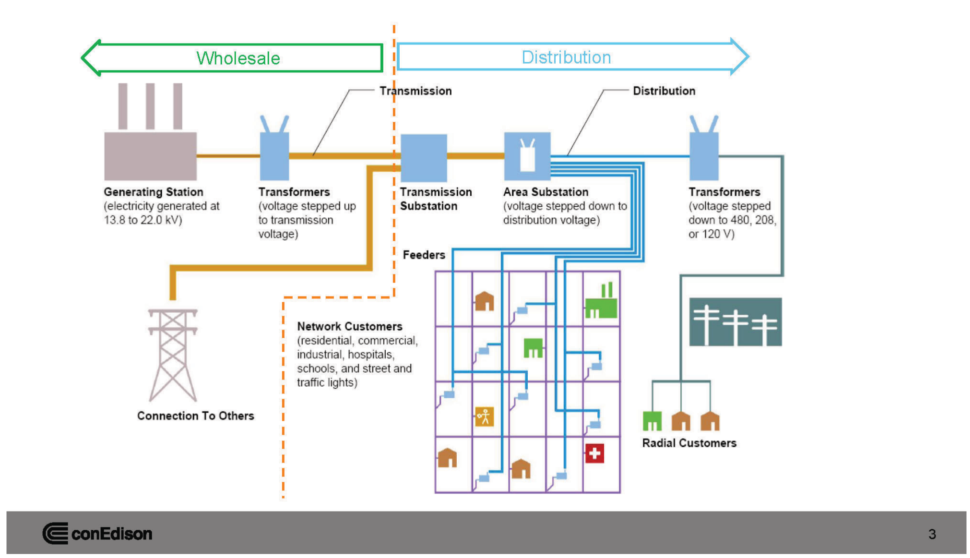
Then it's also a step in contingency planning, so if we have to replace a major transformer in the middle of the summer, we might say, "All right, before replacing that transformer, that network, instead of being good to 300 megawatts, now that network is only good to 280 megawatts. 280 megawatts, we have to start taking operational moves, so a line item in there is going to be at a certain level we're going to enact DR. And then if it creeps up, then after that we might do a voltage reduction, or we might start cooling a transformer or something, but it is a step there. It could potentially help us avoid operational moves if it prevents load from creeping up higher.

We are starting this year to experiment with using these resources to actually avoid more localized equipment overload, so instead of a transformer at a substation, we might be talking about a local transformer. And by pilot, I mean we're not going to avoid any operational moves, we're just going to sort of start collecting data, start developing the processes for this stuff so that hopefully in a couple of years we can actually use this to avoid some operational moves. And yeah, and really be able to count on it, but we have to gather data. And of course, DR is sometimes used for our non-wires solutions such as BQDM.

This is just high level, like what does it look like, so this is a test event for our contingency program. Normally I just call one network at a time, but this is what happens when I call everything at once. The red curve is what the load was that day, and then what it would have been during the event hours, so the baseline during the event hours. And then the blue is showing during the event hours what meter load was, and this is just for the customers who I have participating in my C&I program. You can see it's a 300 megawatt drop. I mean, it's a clear, clear, visible drop that you can really see there. And again, this is not the whole system, this is just the customers who participate.

Then this is what it looks like for on a peak shaving day, right? Again, we said it's spread out throughout the day, so even though we had almost 300 megawatts last year, I think it was 280 or so, it spread out throughout the day so you don't see it all happening at the same time. But it does give you that sustained reduction. And if you look at individual networks, you'll see the peak on each of the individual networks fall off. This is just kind of the beginning of what can be used, really, for dispatching distributed resources to solve local problems.

What does the future look like? In the future we want to have, very, very targeted, localized, real-time dispatch, so that means now I call the whole network. Did I really need to call the whole network? Maybe I just needed to call three blocks in order to resolve a specific contingency, so again, we're starting to experiment with doing that so that hopefully within a few years we'll have



SLIDE 5 View Slide at: https://bit.ly/3aA5Rpe

the processes developed and the data available so that we can really start using it as an operational tool.

Right now, we really are only looking at sort of primary distribution equipment, substation equipment for this contingency stuff. But in the long run, we want to get down to be able to avoid secondary overloads from this. And we also want to be able to avoid specific operational moves, so right now when we call it, certainly for the really localized problems, we're not relying on this stuff, but the idea is that after we get a better handle on this, we'll be able to avoid these moves.

So, now maybe my operational move is to roll a backup generator somewhere. I'm still going to do that, right? But hopefully in a few years, we'll be able to avoid certain backup generator rolls, be able to avoid spraying some transformers, and most importantly load-shedding or having to move load to a different area, and voltage reductions. And then also, our goal is to be able to connect the dispatch of our distributive resources to our load flow analysis system and have that trigger it, so the I guess standard ADMS stuff that we're all talking about now, but this is kind of like the baby steps for us to get there, right?

Now the systems aren't connected, right, so we manually run in our load flow analysis system, and then we manually call DR, but once we get that down, we want to connect the two so that we can call it for the more localized issues. So, lots of challenges, we all basically know what they are, but I'll just say them again. So, forecasting, right? I won't be able to avoid operational moves if I don't know what I'm going to have, right? Because a lot of times, especially for contingencies, this is all happening really fast, so if we don't reliably know what we're going to be able to reduce, at least to a certain probability level, we're still going to have to roll that backup generator.

We've got to figure out how to forecast it better. And part of that is just gathering data, right? Now we're talking about it all in theory, but I won't be able to do that forecasting until I have data, which is why we're starting to experiment with it now, so that in a few years we will have that data and be able to do the forecasting and assess what the reliability is. I'm not even going to go into IT system integration, I'm just going to leave it at that.

And then payment structures. How do we incentivize... How do we make this a worthwhile incentive structure for customers that they can easily understand, that I can explain on one sheet of paper, but that will still give them the right incentives to be able not just to want to perform, but to be able to reliably perform. That's the key. And then tied to that is, how do we even value this stuff, right? So, right now at ConEd, we value the peak shaving portion of our DR based on the avoided T&D infrastructure, and some other things on the side, but that's the big one for us.

But on the reliability side, it's very hard to quantify. And if anybody has any ideas, please come talk to me. That's something we're really struggling with. But in the long run, we're hoping to say, "Okay, we avoided rolling a generator that would have cost X dollars. That's how much this is. We avoided transformer spray," et cetera, so we're hoping that this will help us gather the data for that. All right. Any questions?

Dave Hyland: Dave Hyland from Zen Ecosystems. Explain the challenges with your control center. Is that an issue, the guys that actually push the buttons, that run everything?

Horowitz: I'll say probably three years ago when I went to the control centers and said, "Hey, it looks like you guys are having something going on. Do you need DR?"

They said, "What?"

And I said, "You know, demand response," and talked about it.

And they said, "I'm busy now,"

And then what we started doing is doing a lot of training for the control centers, so that means training every single operator, and they're on shifts, so that's a lot of training, but training every single... And I have five control centers, so training every single operator to understand, and not just the operators. Even more important than that are the engineers who back up the operators, because the operators do not have time to think of this, right? I mean, this is something they use... On average, we call our peak shaving four days a year, right? So, they don't have time to think about something that they're using 16 hours a year when they have bigger problems.

But as soon as we started training the engineers who back them up, now they call me. I do not call them anymore, right? They think of this as a resource. We show them the graphs where they actually see the load come down. Last year, our peak day, I mean, we saved over 300 megawatts off system peak, and that was in connection with NYISO, that wasn't just us, but altogether 300 megawatts off system peak, which is something that they take very seriously. They're very interested in this now. Yeah.

Joseph Childs: Joseph Childs from Eaton. In terms of valuing resources on the distribution system, do you have numbers for the value of minimizing or reducing the number of distribution automation equipment operations (LTCs, voltage regulators, capacitor banks) or other basic distribution equipment? Because the cost of maintaining the equipment is directly related to the number of operations.

Horowitz: You're saying what the O&M reduction for not operating a capacity control one less time?

Childs: Yes, one less time, or 50 less times.

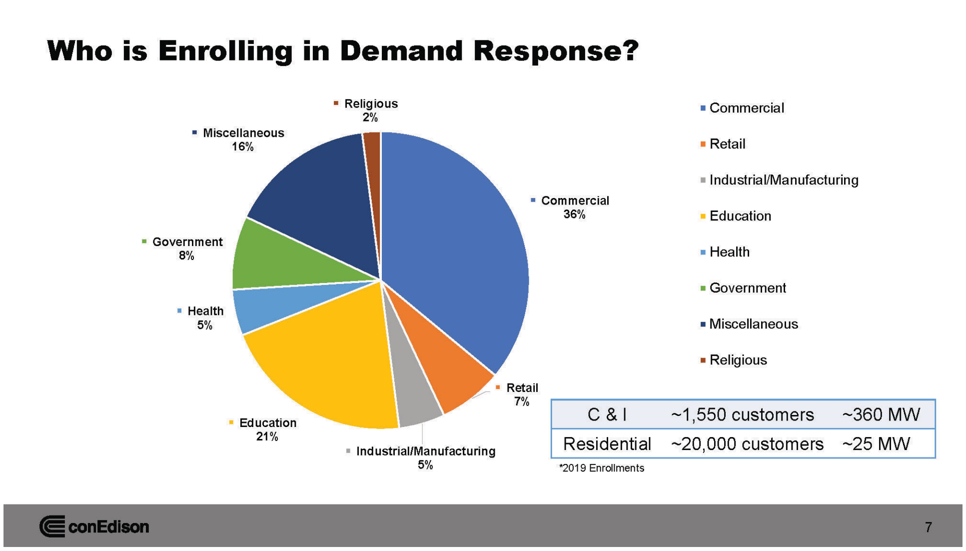
Horowitz: Probably we have that. I don't know. That's definitely something to think about.

Scott: I've got a couple of small suggestions for you. Ideally, those buildings with the window units should be rebuilt.

Horowitz: I'll tell the mayor.

Scott: Got to start somewhere. Aside from that, have you considered a contest like the refrigerator, the Golden Carrot, where you have a design competition for window units?

Horowitz: Are you saying designing window units to–



SLIDE 6 View Slide at: https://bit.ly/2RirrXE

Scott: Be more demand-and-energy-efficient.

Horowitz: Yeah. I think in the long run, we see everything sort of moving to the Wi-Fi-enabled units that can then... We're trying to incentivize Energy Star, Wi-Fi-enabled window units, and that will, A) be more efficient in the first plane, and then B) allow us to control them for DR events. But in the interim, we give out these, we call them SmartAC kits, that kind of make your old, dumb air conditioner into a smart air conditioner that we can control, so that's kind of the bridge solution over there.

Speaker 6: So, just wondering if you can expand a little bit on what kind of metering infrastructure do you see in your territory. Is it a lot more AMI penetration in the territory that enabled you to do all the DRs? And I also want to know if distributive generative, like solar rooftops, are affecting your strategies in any way.

Horowitz: For the metering question, we are in the process of deploying full AMI to our entire service territory. That's going to take until 2022. In order to participate in our performance-based programs, you must have an interval meter, so we have these old I guess dumb interval meters that customers use to participate until we transition into AMI. But hopefully by 2022, we'll have that full data. And then yeah, the DG impacts us.

Horowitz: I'll say the one nice thing about providing power to New York City is that you have such a high power density and such little rooftop space, and just free space in general, that the solar doesn't cause us the same problems, at least in New York City, as it does everywhere else. We do see the same problems as everybody else, like in Westchester and parts of Staten Island, and our sister utility, Orange & Rockland, has that as well. In the near future, we are not going to see back feeding happening from solar in Manhattan. It's just not possible.

Speaker 7: So, when you call an event, does your ADMS give the operators feedback right away? Do you have enough sensors tied to ADMS that it can say, "All right, we got what we needed on this feeder?" Or are you relying on–

Horowitz: Okay, first of all, no ADMS. We're not there yet.

Speaker 7: Okay. So SCADA.

Horowitz: Yeah.

Horowitz: They can see in real-time what the load is everywhere. It's hard for them in real time to assess what of that is attributed to demand response and what of that is just happened. When you're looking system-wide, the load shape is fairly predictable, so you can see it fall off, but if you're looking at just a single network... Some of our networks are just 100 megawatts, right? The load shape there is not super predictable, so it's hard to assess that on real time right now.

Speaker 7: So, you have to go back with your AMI data and validate it that way?

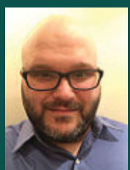
Horowitz: Yeah. Usually within a couple of days, we have an approximate impact, and then within two weeks we get most of the data back to have that impact.

Richard Barone: Richard Barone, Hawaiian Electric. In Manhattan in particular, given the compact network topology, I was just wondering how you deal with the issue of actually targeting and dispatching resources.

Horowitz: Yeah, so we're working on that now. This is the first year that... Well, okay, so if you're just talking about a single network, there what we'll see is, let's say we lose two, three feeders in a network on a hot day, so we'll call the entire network, right, so that's a simple one. But if we have something that's causing a more localized problem, what we're doing now really is just... It's almost a pilot, so I still have to call the entire network, but what we'll do is we'll run our load flow software before and after to see if it alleviated the problem, if those resources did. And then hopefully in the future, we'll be able to call them more locally, but now we're just piloting it with the whole thing.

National Grid's Journey from BYOT to BYOD

From 39th PLMA Conference



Michael Smith
National Grid

Chris Ashley
EnergyHub

Steve Wheat
Sunrun

Michael Smith: A little background on National Grid, we are an electric and gas utility serving 3.4 million customers across New York and Massachusetts and Rhode Island. Since 2015, we've been running a bring-your-own-thermostat program, which just last year in 2018 we were able to evolve into a bring-your-own-device program. It's been a goal of ours since the beginning, and we're really excited about it, so that's why we invited Chris and Steve to come and talk about it.

Steve Wheat: These three partners that we have up here have very different sets of relationships. National Grid has different relationships with their customers than Sunrun does. EnergyHub as the program administrator has different relationships with both Sunrun and National Grid. So, you can imagine almost five Venn diagrams all piled on top of each other, and then turn that into a three-dimensional image, and that's what contracting is like, especially on the tight timelines that we had to turn this into a BYOD program over the summer last year.

As we developed this presentation, what we wanted to take everybody through was the way each of the partners thought in three separate phases of this project, so the first is program development, and then we'll go into the operations during the summer, and then we'll finish up with what the results of the program were and how we're planning for future seasons. And then with that, Mike, what was National Grid thinking about contracting?

Smith: Setting up a program, we were looking at two main areas, keeping it cost-effective, and being able to actually engage customers to participate. As far as cost-effectiveness goes, we're always looking to develop programs that have more benefits than cost to our customers. And from 2015 when we started doing BYOT, we didn't have the benefit structure that allowed us to do that. Last year in Massachusetts, our new avoided cost study revealed that in addition to there being a benefit to the annual peak reduction, there was significant benefit for us if we could reduce daily peaks in July and August, so that brought us back to thinking about batteries again.

Then we knew there were customers with batteries, because in Massachusetts there's a smart incentive, which pays customers an incentive for installing solar, and they're eligible for an additional incentive for pairing it with storage, so we knew these customers were there.

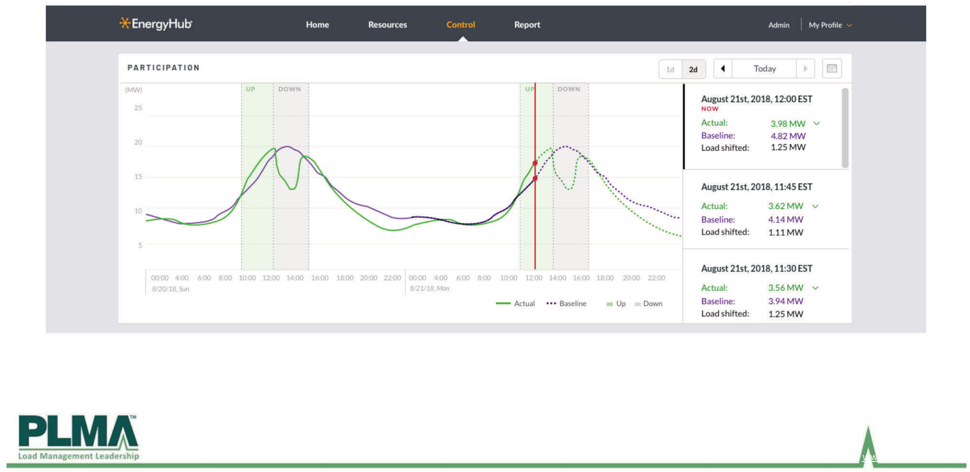
We did not know how to engage them, and we did not know if they would really be interested in doing this, so the struggle for us was how to engage the customers, how to convince them to take their backup reliability resource and give us the keys for DR purposes. And that was something we really relied on that summer one for, so Steve, if you have some more thoughts.

Wheat: One of the other things we wanted to point your attention to is that even though all three partners were aligned in trying to get to the finish line on this, as you can see, what we're focused on is already pretty divergent. So, the main points that Sunrun wants to get out of the program versus EnergyHub and National Grid don't necessarily align right away, and we have to go flexibly into the contracting period to get to where we want to go.

And as Mike just mentioned, so Sunrun is already deploying energy storage paired with solar in their territory as we wind into this program, but we are limited by the fact that we can't export energy from those batteries in 2018. So, the regulatory landscape means that we are selling customers an asset, which is only going to be used for backup power when the grid goes down. So, the challenge for Sunrun is, how do we go back to these customers and to new customers that are ponying up extra money for a battery and convince them that they should be sharing this energy with the utility, or helping make the community more resilient? And a lot of things that aren't necessarily the focus of the customers who are buying these assets in the first place.

Chris Ashley: I think it's interesting that you have the utility that has this new need if they can have this flexible resource every day. Sunrun's out there working with customers anyway. From our standpoint, that lends itself really well to the bring-your-own-device model. And so how can we take what we've done in the thermostat world, and the exciting piece here is these are bigger, they're more flexible, and how do we apply that learning to batteries? So, a big part of the program development from EnergyHub's perspective was around applying the BYO model.

And then the second piece was as Mike mentioned a tight timeline here, how do we go from contracting in late-March, early-April, between EnergyHub and National Grid to then have a program set up for the summer that was going to give us results that would inform their cost-effective business case? So, a lot of coordination around just the speed and how do you do things quickly, because this world doesn't always move fast, so that was another interesting component here.



SLIDE 7 View Slide at: https://bit.ly/2tBG4wq

Wheat: Now we get to where the rubber meets the road. And one of the important things to remember is when we have gotten to this point, each of the partners and I know this from working with them as we were contracting, did not get everything that they wanted. All of us had to give up some semblance of control in order to make this work, and especially make it work on a quick timeline. But as you can see, all three partners are now focused and aligned, the program is operational. We want to all be responding to events, increasing the energy that we're dispatching for each event, monitoring what the customer experience is and making sure that all of the customers in the program are happy with what's happening with this resource, which is in an experimental kind of program.

Mike, as this was the first time National Grid was doing this with batteries, what were you guys going into this summer waiting to hit the giant red button? What were you thinking about?

Smith: Our two primary focuses were our ability to forecast and execute dispatch of these resources, and then understanding the customer experience with this type of program and how it differs from thermostats. While we have very ambitious goals for this program in the future, reducing daily peaks for two months of the summer, we decided for year one that that wasn't really the best approach. We needed to understand more about how these resources worked before we did that, so we focused on a limited dispatch schedule to really understand event performance, customer experience, how it may compromise their ability to use their battery for backup and if that becomes an issue. And I know that was something you guys were concerned about too.

Wheat: Yeah, totally. So, what you're looking at now is V1 of what a BYOD co-branded website for a solar and storage company and a utility lookalike. We're actually really proud of already how this looks for next year's program. We were mainly focused on how these batteries without the ability to export would work in this system when they were called, and whether or not customers would even notice it was happening, whether they cared, whether they were excited about it. These are all things that we'll get into when we show you some of the graphs later. But yeah, as we went into operations, a lot of this was still wait and see what happens based on the constraints in the market.

Chris, you're used to controlling something like 10-to-50,000 thermostats. How did you feel going into controlling a few dozen batteries?

Ashley: It's different. Going back to Mike's point about limited dispatch schedules, okay, this was about the learning. And so, our focus was on our customers enrolling. If you can get a dozen customers, that's a good thing, that's data that you can collect and use, so is the enrollment happening, and then what are the lessons learned from that enrollment process. I talked a little bit about the flexibility to make adjustments along the way would be important. And in this case, you think about a thermostat, a lot of that, it's a couple hundred dollar purchase. A customer might do that online, they might be willing to sign up to a program by clicking something on their phone.

A battery, we learned, is a little bit different, so the BYO model still works, but customers aren't just buying this on a whim through the internet. There's a lot of interpersonal interaction with a real expert that goes into the battery sale, and so we were embedding the DR message into that interaction between Sunrun, the expert and the customer. And doing it on the front end, learning that going back to a customer that already had a battery, there just weren't that many customers that had batteries, so the idea was, how do you use the DR to help drive more battery sales? And embedded into the front end of the conversation, so that was one BYO learning.

And then I think the second piece for us during the actual operations of the program was, to Mike's point, it was the clean execution. So, are we running events, is the communication working from National Grid to EnergyHub to Sunrun? Is the data flowing? Are we getting the results that we can use to inform future program design? And I think that was sort of the operational phase.

I mean, it was modest, but it was exciting to be actually doing this and running the batteries.

So, across the board, the group of us were all aligned. The question was, how would this go? I think Steve talked about our divergent interests in the front of this, but I think one commonality was we all wanted to grow this into a larger program. And so, as we got into the results and the future planning, the common theme across all three companies was, does this inform a business case to do something bigger in 2019 and to deploy a longer-term contract to continue this? So, we were united in this desire to grow things.

And the short answer is, it went really well. As a group, we collaborated really well. We were flexible, we made adjustments, we learned from those. We successfully enrolled participants, we ran four DR events, we collected data from those events that could inform all of these decisions we're now making and have made for 2019. And we had incredibly impressive results, 0.15 KW per participant, so that was the mic-drop moment. And, of course, this business case makes all the sense in the world, right?

Wheat: The good news is that we set up this program, we stood it up very quickly, we were all flexible in contracting, and then when the bat phone rang, all of these batteries responded when they needed to. So, when the asset was called, the asset was there. The bad news is that the regulatory framework in Massachusetts didn't allow us to really do with these assets what we could, and that's what's reflected in the graphs that you can see here.

To break it down, that trailing yellow bit that starts in the top left is the solar production. These events were between 2:00 and 5:00 PM, so you get solar every day at that time. The blue line going relatively evenly across is the customer load, and then that orange-colored triangle on the left side and trapezoid on the right side are the battery production. So, what this graph shows is that when you are not allowed to export from a battery, and most customers don't get home from their jobs to turn on the TVs and everything else until after 5:00, there is not that much load to drop. So, if you're entirely using this asset only to drop existing load, you are not going to get a whole lot.

And this was actually a good customer. This is one customer on one event day. A lot of our customers had zero load to drop. The solar was covering the entire load from 2:00 to 5:00 PM. If you look on the right-hand side, you can see if this battery was allowed to export for the exact same event, you get four times the energy out of it, so it looks more like a three KW discharge instead of a 0.16 average.

Ashley: Mike, so where do we go?

Smith: Steve kind of gave it away already, but the good news is that regulatory policies change. Our regulator in Massachusetts is going to let us export moving forward, so we can now take full advantage of these resources and do more targeted events to help drive more benefit from the program. Additionally, because of this, I think we're ready to move forward with our expanded resource usage and do daily DR events, and do daily calls in July and August, and fully leverage that benefit. As a result, I think we need to do a little more than we did in 2018 to drive customer interest, so we're greatly increasing the incentive to increase customer interest in participation.

And as Chris mentioned, our plan is really to make a program that's going to grow, so for 2019 we're adding some additional partners of Vivant Solar, Tesla and Pika Energy. And we're hoping to go from dozens to hundreds and then see where it goes from there, but this is a very successful first year, and we're really excited about the future. And with that, if there are any questions, we'll take them.

Ashley: We're confident that $275 a kilowatt will work across all of your service territories, so you should feel good about that.

Shira Horowitz: Shira from ConEd. Did you guys think about trying to use the batteries when there's no sun at all, just for long run, duck curve type problems?

Ashley: The focus here last summer was National Grid's peak times, whether the sun was shining or not. So, the idea was that if the battery had been charged by the sun and the event was dictated by their peak need, it didn't really matter if there was... It almost was ignoring what the solar resource was doing at the time. If there was something on the battery that they could use and they needed it, they tapped into it, basically, if that makes sense.

Wheat: The event windows already for next year are going to be between 2:00 and 7:00, and that will be a rotating three-hour block within a larger window, so already in year two we're expanding it to hopefully get into a little bit more of that nighttime peak. But I think it's also important to remember that mainly in ISO New England territory, there's a lot of transmission charges that happen from peak summer days, and I think the hours reflected in 2018 reflected those costs as well and reducing them.

Ashley: And it's doing it every day in July and August that allows National Grid to get to this high customer incentive, just that constant usage is what drives the value.

Smith: Following up on Shira's presentation, in National Grid in any of the three states, we're not quite at your level in our ability to forecast and provide grid services, so really we're just focusing on sort of ISO peak times.

Mark Martinez: Mark Martinez with SoCal Edison. So, batteries do abound, however there is a battery, and then there is an inverter, and then there is a battery integrator, and there are clouds that are stacked in there. So, the challenge that we've had is basically there are cloud systems and API's and so forth. Could you explain exactly what you're talking to? You're not talking to the battery, and there's a smart inverter, and then there's the integration, because Pika is using a smart inverter, and then there's Panasonic cell whatever. So, explain a little bit about the details, because I think the challenge might be in the API connectivity and how we deal with that connection.

Ashley: The communication is National Grid is accessing this portfolio through our platform. We have an API integration with Sunrun, and Sunrun controls the individual battery through your battery control system.

Wheat: Right, so Sunrun and EnergyHub are both aggregators whose headends are talking to one another. As we step into future iterations of this program, we can step into deeper integrations, and also offer shaped dispatch in however the utility is going to require it. We designed this contract to be pretty low-lift in this first season, that allows us to step into deeper and deeper integrations and more flexible battery response over time.

Ashley: But, Mark, the way we have been thinking about it for 2019 and beyond is there's kind of two options. EnergyHub, we can integrate with their headend, or for some of the other battery providers, we might instead integrate with the inverter company and do the control that way. And those are both options that are on the table.

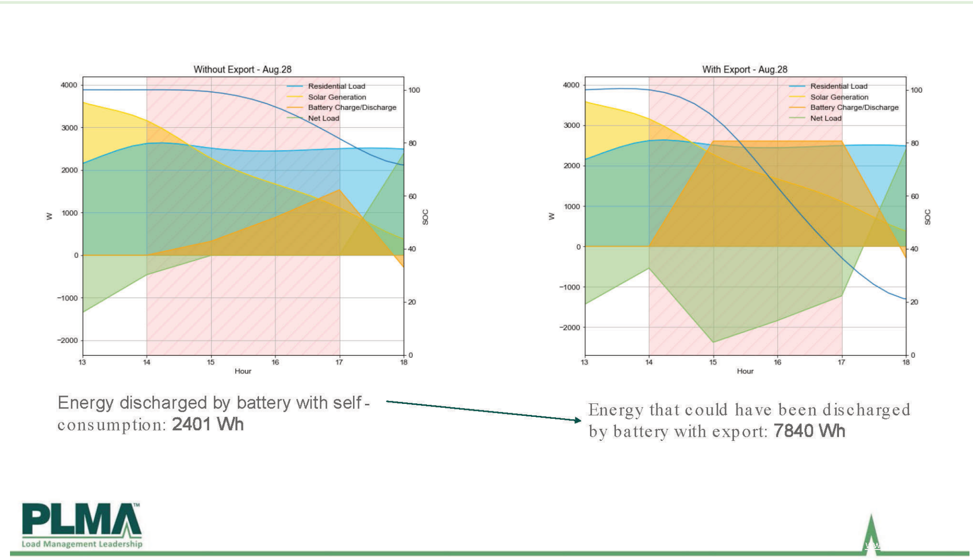
Jeff Cacoil: Jeff Cacoil, EnelX. Since these residential customers presumably bought the batteries for resilience needs, do you think there is going to be any fatigue issues if you're running them every day, people are going to be thinking, "Hey, wait. I thought my battery was going to be available for a catastrophe?"

Wheat: It was a great question that we wanted to get around for 2018, because our customers were restricted to resilience only. It becomes somewhat of a moot point in 2019, because across National Grid's territory and the State of Massachusetts, there's an incentive called smart, and that incentive, which it's going to roll into our customer pricing, requires a number of discharges, nameplate discharges from the battery every year. So, the paradigm in Massachusetts going forward will look more like time of use than it does resilience only, so it kind of bridges the gap between our customers willing to be giving something up that they find valuable versus, "This is how the battery operates, this is the normal battery operations."

Ashley: The other thing that National Grid has agreed to in some of the fine print is, and it's a little bit subjective, but they've basically given the customer their assurance that they will be not just hitting the button every day. It will be up to every day, but it probably is more likely to be 40 of the days in July and August. And they will also be keeping an eye on localized weather. And so if it looks like a weather event is imminent that would be the reason...

And the resiliency of the battery may matter, they're not likely to use it for DR. So, in the summer they'd be keeping an eye on thunderstorms and things like that, so that will be part of the learning in 2019, is how you balance that. But the utility is definitely cognizant of that and does not want to put a customer in a position where the power goes out and the battery's dead, because they could just run a DR event.

Wheat: Sunrun also interviewed all of our customers after the program was over to see how they felt about the program and the system, and there was some interesting feedback that we got from customers. And the way that a company like Sunrun interacts with customers in general and how everybody talks about how the utilities and solar companies talk about each other, that paradigm is already starting to shift that we can see, where we had customers that actually... They bought the battery because they were afraid of outages from the utility, and then at the end of the season they're like, "Oh, this is pretty cool, that the utility is doing this. It's cool that National Grid is involved in this kind of thing."



SLIDE 8 View Slide at: https://bit.ly/36jscnQ

Wheat: There was one customer who really appreciated... There was an outage, and when he saw the linemen out there doing the work, he started to appreciate more all the work that went into utilities keeping things up. But the early indications are that when we interview customers, the co-marketing angle works well to drive beneficial customer thoughts about their utility.

Dave Hyland: Can you say something about what you had to do internally at Grid to get this program up and running? And what did you have to do to sell it internally?

Smith: I wish Paul was here, because I think he would have a better perspective since he was the one who had to battle. I don't think there was that much internal resistance to this. I think DERs are obviously on the roadmap. We're looking to increase the penetration of storage for our customers. This is giving customers a value stream to make that decision, so from that perspective I don't think there was. With the export issue, I think there's probably a part of the company that sees a risk and a worry and a concern from that, but that wasn't necessarily our policy. But I don't think it was that much internal stuff.

Ashley: I think one thing Paul did a really good job was he started with that premise of cost-effectiveness. It sounds a little crazy that a battery program would be cost-effective, but they weren't buying the batteries, and so Paul was somewhat maniacal about making sure that what we were setting up for program terms, what National Grid was spending money on, was part of a cost-effective approach. And so that helped him with the internal... He basically said, "If I can stay within these lanes, I can do this." And then he focused on staying within those lanes.

Speaker 17: So, I have a question about the economics of the battery. How did you value, I guess, the battery itself and the capacity available given that the capacity is decreasing over the cycle life of the battery?

Smith: I'll start again. Wishing Paul was here, because he had this really large, elaborate spreadsheet that he made Chris look at every day. And I think we took a really conservative approach for the capacity available. I think probably what we saw in the graph or chart that Steve showed is more favorable than we expected, so in that sense I don't think that's a big concern. Maybe later in the life of the battery, that will be something to think about, but on a programmatic standpoint, I think it works based on the assumptions we used.

Ashley: And it's pay for performance, so the $275 a kilo... so, going forward, it's based on... So, if something degrades in the performance where the customer chooses to make less of their battery available, that's their prerogative. At the end of the year, National Grid is going to add up what they did across all the events, and it's between the battery and the customer's behavior will drive how the customer gets paid. And so, there's alignment, because it's pay for performance.

Wheat: One of the reasons that we really like a BYOD type of design for a battery program is because that's organically how the market grows. The difference between an NWA in some cases and a utility-wide program is that you're not paying extra customer acquisition cost to drive penetration on a single feeder. So, as this program expands, obviously the number of customers enrolled expands and then sends up to the aggregator and the program administrator to manage the batteries that are older in the fleet versus the batteries that are newer in the fleet, but still delivering the overall optimized dispatch for what the utility needs.

Joseph Childs: Joseph Childs with Eaton. Am I missing something in the units of 275 per KW? Is that per event, per month, per week, per hour?

Ashley: $275 a kilowatt year.

Presentation slides available at https://bit.ly/2uoP8EM

Integrated DSM: The Journey Continues

From Load Management Dialogues

Denise Kuehn
Austin Energy

Jennifer Potter
Hawaii Public Utilities Commission

George Beatty
Xcel Energy

Moderator
Olivia Patterson
Opinion Dynamics

Moderator
Sharon Mullin
Navigant

Olivia Patterson: Thank you for joining the Integrated Demand-Side Management: The Journey Continues webinar. AESP and PLMA have come together to begin exploring how best to advance integrated demand side management initiatives through sharing of best practices and lessons learned from the field. This webinar is brought to you by this joint partnership of AESP and PLMA.

Patterson: I wanted to give you a brief overview before we dive into each of our panelists' short presentations. First off, I think we wanted to just cover that as most of us probably know, traditionally, utilities have separated their energy efficiency and demand response portfolios into distinct and isolated portfolios. However, as we all know, distributed energy resources are deployed across the distribution grid, and policy mandates have been shifting, so utilities and implementers alike are repurposing their demand side management programs towards integrated approaches.

These integrated programs focus on technologies with the functionality to decrease, store, or increase both energy usage and demand, thereby combining EE, ER, and DER programs. Conceptually, that's what we think of when we think about integrated demand-side management. But we want to hear from those folks who are experiencing this on their day-to-day, so this webinar is structured to have our panelists briefly provide their perspectives on integrated demand-side management.

I'm excited to introduce ou first panelist, George Beatty, to share his thoughts and wisdom on navigating the new terrain of integrated demand-side management. George Beatty has been an associate product developer at Xcel Energy since fall 2008, and prior to that, he worked in the energy efficiency engineering group for eight and a half years. He supported a variety of demand-side management programs, including saver switch, data centers, compressed air, motors and custom across several states.

George Beatty: When people hear about integrated demand-side management, or at least when I hear about it, I mostly think of smart thermostats. There's been a large evolution of devices. We've gone from analog devices all the way up to digital smart devices. The most impactful changes have been in the last eight years, with the introduction of smart connected thermostats, like nest and ecobee, leaving behind the days of the analog devices and the programmable thermostats that apparently nobody could figure out how to program. Now we're staring down the barrel of algorithms and AI packages to help optimize our smart thermostats for us.

So, how have the programs evolved with the devices? Some utilities have had programmable thermostat offerings, but I think a lot of that stopped when Energy Star sunset their programmable thermostat standard at the end of 2009. Here at Xcel Energy, we have a direct install with the programming of programmable thermostats through our Home Energy Squad program, and that does include some smart connect devices, like ecobee devices.

As far as smart thermostats go, in 2017, we had our AC Rewards program approved in Minnesota and Colorado, and that was mostly a demand response program really focusing on transitioning from our direct load control devices, like saver switches, to a device that everybody wants in their house, a smart thermostat. More recently, over the summers of 2017 and 2018, as well as over winter of 2018-19, we did an optimization pilot where we tested those algorithms and AI type packages to see how we could further optimize thermostat operation for our customers.

That brings us to the evolution of Xcel's programs today. What's next? We are currently looking at smart thermostats in multiple programs. Typically, we have bucketed our programs, where one program offers their one thing and then another program offers their one or two things or handful of offerings. But now we're really looking at spreading out devices like smart thermostats into as many programs as we can, and giving our customer a better experience, so they're not shuffled around between programs. That's really been the beginning of our integrated demand-side management journey. We're trying to pull together our energy efficiency and demand response programs.

We were planning to really tackle that in full force with our most recent triennial filing. That was going to be

IDSM version 1.0 for Xcel Energy, but instead, our regulators decided to go with a one year plan extension, which kind of slowed us up a little bit because that extension was looked at more of a continuation of our previous filing. So, we're looking at really tackling this in earnest with our next triennial filing.

Technology is moving fast. The programs are trying to keep up the best that we can. The rules? Well, let's talk about the rules.

So, challenges. Back in June 2018, we tried to do some integrated DSM. In 2018-19, we tried to do some integrated DSM type of filings with our regulators, the first one being the Big Tank. That was our code word for it. Big Tank sounds like a stage name for a Nathan's Hot Dog eating contest champion, but it's not. It's actually, what we were trying to do was get permission to rebate through DSM programs where we could shift the load, and that would include products like ice storage shifting load. People that work in this industry know that shifting load doesn't always mean saving energy, and we are still tied to our DSM rules of saving energy. So unfortunately, our Big Tank filing was rejected, mostly due to the fact that it did not reduce overall energy use. That's a holdover from DSM and energy efficiency programs that everybody's been really implementing for a long time.

In 2019, we did an EV charging perks pilot. That included both load shifting and some energy efficiency savings from Energy Star Level 2 chargers. However, that was also rejected, due to not reducing overall energy use and no quantifiable kWh savings. Those were some stumbling points for us, but I think it's really important in both of those cases to not focus on the actual decision of these proposals being rejected, but focus on the rule. From a policy standpoint, it's that energy use rule that is somewhat preventing us from really embracing IDSM, integrated demand-side management.

So the rules were written for one set of situations, for energy efficiency, but it's not really conducive for where things are going with demand response and a lot of our programs that we're looking at. Some of our other challenges include shifting priorities for device manufacturers. Data sharing is always a big deal. Everybody wants to own the customer experience. The device manufacturers, the utilities, everybody. There's always a little bit of a battle for that.

There are some technology challenges, API availability, fees. Living in the energy efficiency world, we always have to worry about cost spend. So, these do come into play. As far as challenges with algorithms and optimization, is that our future? Maybe, maybe not. We have some competition there. There's an evolving Energy Star standard that could threaten those device offerings. In some cases, simple DR controls are usually pretty cost-effective, or pretty effective at reducing load during the hot, humid days. So, do we actually need those algorithms?

If you had talked to those manufacturers of those algorithms or the programmers, they would say, absolutely. I'd tend to agree with them, because they do offer other value besides just the standard demand response, and beyond just energy efficiency.

Sharon Mullen: I would like to introduce Denise Kuehn from Austin Energy, who will be talking to us from a portfolio perspective. Denise was responsible for leading the planning and implementation of several of Austin's sustainability customer programs. With her electrical engineering and MBA degree, she's worked in generation, transmission, and distribution, renewable, customer service, sales, operational analysis, and sustainability for various utilities consulting and Fortune 100 companies, leading or contributing to over 50 strategic and change management initiatives.

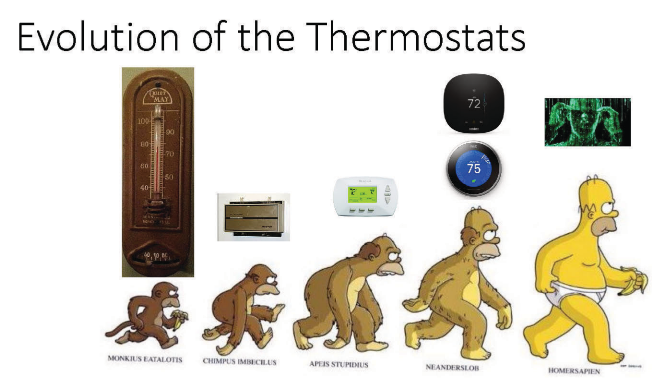
Denise Kuehn: How can we take all of the efforts that are across our industry and create even another piece of the synergy to take it to the next level? It's going to take all of us doing things like this brainstorming and working together to get there. So, why are we doing this? A lot of is truly because we're focusing on our customers and the community that we serve. Our goal is to deliver products and services that are valued by our customer. That's a key piece here, is the value piece, and we'll talk a little bit more about that as we share some of the perspective of the integrated demand-side management path, the long term vision, why we're moving in this direction, and the challenges we have faced. We'll even throw in some of the approaches that we've used to overcome them.

This is really a simple graphic that looks at the big picture that George just talked about. There are a lot of different pieces to this, when it looks at, how do we impact the demand side, the customer side? How do we help them make good decisions with regard to energy efficiency, demand response, renewables, grid optimization, all the different variations of storage, from thermal, electric vehicles, just to name a few. There are a lot of things out in our industry, and the irony here is for decades, the utility industry really didn't move a lot. Then about 10 years ago, it's totally turned the industry on its head.

I think both the utilities I worked for before had gone 18-19 years without a rate increase because they had the formula down. Now, with the evolution of technology, there's a lot more opportunities for distributed energy and management, so now they're looking at it differently. However, the challenge from a utility perspective is many of them, many utilities, have what is defined as 20-40 years of debt commitments that they've already made with the centralized utility model. That gets into the generation, the transmission, the distribution, even customer offices.

So, how do we balance all of these things? Transitioning to this new distributed model really brings this challenge of stranded assets, more complexity, risk, cost, more work for each of us in trying to coordinate with departments we didn't have to before. TMD, IT, really looking at it from a governmental affairs perspective. It goes on and on. Why, really, are we doing this?

We talk about the reasons of why this is of benefit to the utility, and why utilities have now focused resources that are chipping away, basically, on a centralized model. Why are we doing that? It really gets back to the drivers. The customer, the industry, and the policy.



SLIDE 9 View Slide at: https://bit.ly/2REkVcQ

Looking at it from a customer perspective, they're pushing innovation. Customers are expecting that they have a good experience dealing with our company, or they're going to go somewhere else. Basically, deliver what the customer wants, or they'll go to your competition. Their concerns are cost, convenience, reliability, ease of use, transparency. All of these items impact the customer's perception of the product.

Utilities, for decades, were in a regulated market. Now that we're in deregulated, these customers are dynamic, and they have a choice to go somewhere else. So, it's about creating that customer experience in which they decide to stay with that utility. One of the things that they're pushing is they want to be able to access their information from various channels 24 hours a day, 7 days a week, and they'd like it personalized so it's an easy, efficient use of their time.

The other aspect of this really is from the utility perspective. How do we deliver what the customer wants and balance that, those fixed charges and infrastructure we've already invested into, along with bringing in these new resources? That really gets into reducing the cost of delivery, or making it more flexible, more dynamic.

You've seen a lot more in the utility industry, in all the utilities I've been working with, looking at process improvements and automations. Various ISO, LEAN, Six Sigma... Also looking at all these different databases that are both internal and external and centralizing it so you have a 360-degree view as a customer, using journey mapping to really understand, what are your customers seeing when they work with you, when they deal with you? And from the perspective of your partners, if you have contractors that work for you, what are they seeing? The different vendors.

Then, also, utilities are using this data to help hedge grid pricing. Now that we have gone to more of an RTO realm, it is very important to know the market and use this data and this information to position your company successfully, as well as using predictive maintenance to increase your reliability. Some customers are even getting more into using telemetry data to offer those customized products and services, based on usage patterns. So, utilities really are implementing various digital options to create that distinctive brand. It's an evolution, though, because you have all of these legacy systems. How are you merging them all together while you're making these investments, some of which have an ability to do a common platform, some of which... the offering's in the utility, because we have such a distinct model. You have to buy different models and basically merge them together.

The other piece to that, then, as we're trying to prioritize our costs, our benefits, is really, how do you define the true cost and value from some of the different products? I've seen utilities offer programs and things that customers have asked for, only to find out that after the investment is made, the customer comes back and the value they have associated with that product is not as high as the cost. How do you identify that ahead of time, whether it's energy efficiency, demand response, renewable storage, whatever it might be?

Finally, this is more something that Jennifer is going to talk about, but it gets into policy. For example, in our industry, ARRA, the American Recovery and Reinvestment Act, invested billions of dollars on energy efficiency, demand response, renewable, and storage, which then changed our industry. It basically reduced a lot of the costs, created these different pilots. So, it will be interesting as she shares with you that direction on the utility industry and its impact.

The next slide really gets into some of the more challenges that we've seen, more from a holistic utility industry. However, these are also from the utilities that I work with. You look at this, and with a decentralized model, as a big picture from the industry, it brings more risk. The utility infrastructure in the US is worth hundreds of billions of dollars. Already, sunk costs that are out there. They're usually aligned with debt, 20-40 years of these investments. That cost is not going to go away, even though we're creating these new DSM resources and renewable resources. It gets into balance and making good decisions on which ones to invest in.

For a regulated utility, it's still a dynamic in which it's more comfortable to make those long-term commitments. However, in a deregulated utility, it is much easier for customers to leave and go with other utilities. Who pays for infrastructure, such as T&D and some of these different strands of costs? That really becomes a challenge on some of these things.

Part of it is education. Education, internal in our industry, with policy holders as well as customers, to help them understand all of these pieces and how they can come together. One of the things that always gets forgotten is how, really, do you create that electron, and does it really go to my house? That's always a question I have with regard to green power. How can you tell me that that wind farm from western Texas is really serving my house here in Austin? That by itself is just to educate them and help them understand how these pieces all work, so that they can make the right investment that best fits their needs. If they do that, that helps them reduce their cost of having to buy another product, their frustration, as well as helping a utility have better customer retention, and the ability to get in to invest in more research and development to provide those products this customer is demanding, as the technology evolves.

That technology gets into a lot of cost, but also a lot of benefit. It goes into artificial intelligence, virtual and augmented reality, intelligent voice assistance. Everything else with the internet of things, if you would. All of these bring both benefits as well as risks with regard to the privacy, the personal information. Our customers are trusting us with some of the most important things to them to protect this information and privacy, and that is a huge order when you see people across the world now can have that ability to hack into these systems. On a daily basis, we're getting all of these challenges with this.

The other piece, really, is they want transparency. Customers want to know, now that you have this personal information, how are you using it? What are you using it for? If you say you're not selling it, as some different people in the industry have realized, don't do it, because customers sooner or later will find out and they won't trust you again. Once that relationship of trust is gone, the customer moves on and it is an expensive cost to get a customer back, much more than having one that is happy and with you on a continuous basis.

In essence, there are a lot of different pieces to this integrated demand-side management. All of it takes planning, working together to create this synergy, and really providing that education to our customers, our policy holders, and even our internal industry stakeholders. As we get into the policy piece, that's what Jenny is going to talk about.

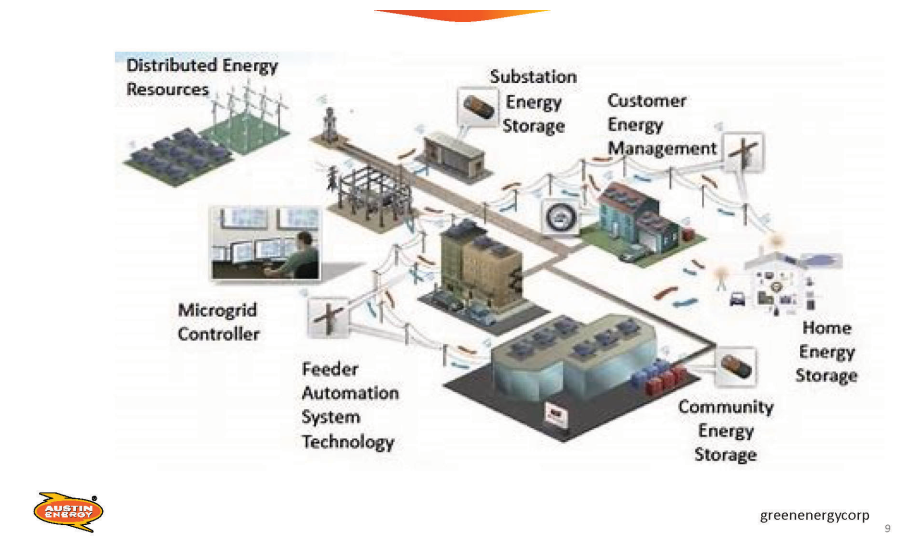
Mullen: We've had a couple of references to regulation and policy issues, and a tease for Jenny Potter, our next speaker. Jenny is serving in her dream job as commissioner with the Hawaii Public Utilities Commission through 2024. She's worked in the energy industry for utilities and research labs over her career and continues to find that the energy sector is impossible to master, and continues to evoke curiosity, challenges, and opportunities to exhaust your mental capacities. Yet she wouldn't change careers for anything.

Jennifer Potter: Thank you so much for having me here to talk about integrated demand-side management. It is one of my favorite topics and will continue to be so for the foreseeable future. What I've provided here on the slide is some work that I did while at Lawrence Berkeley Lab. It was actually my last assignment there, where we evaluated and looked at integrated demand-side management activities across a number of utilities in the country. During that process, we came up with a very ambitious definition for integrated demand-side management, which I'm sharing here now.

We identified... We are invoking, I guess, persuading the industry, to consider integrated demand-side management as three or more of the different demand-side management components, including electric vehicles, energy efficiency, distributed generation, storage, demand response, and time-based rates. So, you would need three in order to truly be an integrated solution for customers.

Typically, what we saw is that time-based rates are that fundamental foundation for adding on energy efficiency and then demand response. So, you would have a trifecta, if you will, with time-based rates being the more manageable solution to offer to customers, without having to do a direct install, for example.

With that in mind, thinking about why integrated demand-side management is so important; there's a number of policy objectives and customer options, choice, experience, as well as the grid needs that really are the foundation, the driving force, for evolving demand-side management into integrated demand-side management. In Hawaii, we have a 100% renewable portfolio standard. Many states across the country are adopting similar standards. Maybe it's 50%, 70%, or even



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100%. One of the foundational mandates that we have in Hawaii is to reduce our reliance on imported fossil fuels related to electricity generation. We've also recently adopted a net zero greenhouse gas emission goal, and that's by 2040. All of these really drive the policy focus of, what are our tools in order to accomplish these goals?

In addition to that, we have this customer experience, this customer option component, where we've had a proliferation of photovoltaic adoption among our customer base. The Hawaiian Electric Companies estimate is around one out of every eight homes in Hawaii has photovoltaic; this customer choice, people already adopted the DER component, and there was a need to develop solutions, connections and rates that would facilitate that interconnection and work with the grid. That's really been a major push as well.

In addition, now, with the proliferation of DERs and also our 100% renewable portfolio standard, we have a lot of renewables on the grid. That's driving this grid need component. We really look to, what is the option on the demand side that can help us meet these policy objectives, still provide the customer choice and experience, and help us manage the grid, when we have so much variability across the hours, and really need to accomplish multiple things at the same time? IDSM is certainly one of the solutions that we've identified and anticipate moving forward and watching this evolve.

This really comes down to energy optimization behind the meter. We need to use the resources behind the meter in terms of help us meet these objectives. I think the biggest takeaway that I can give today is that we will not be able to reach our 100% renewable energy without IDSM or without a suite of DSM measures behind the meter within our customer. It falls under an umbrella concept of Non-Wires Alternatives.

The energy efficiency has always been a gateway drug. I've always thought of it as a gateway drug for demand-side management components and end uses, but I'm now becoming a pretty strong believer that photovoltaics is a gateway drug, as well as electric vehicles. We are seeing a lot of uptake in electric vehicles. Those opportunities, and when I say a gateway drug, that's your in with the customer. That's your opportunity to determine if a customer is installing an electric vehicle charger at a premise, we should be thinking about making that building the most efficient and energy optimized that we can. Can we introduce demand response to it, can we address envelope measures? Can we put them on time of use rates? Can we bundle a package that is customer centric that addresses that specific customer demographic, and it meets their needs while also basically giving them what they want, providing them with the choices that they want?

They're moving the market, so we need to figure out how to facilitate their adoption with the portfolio of options, which is truly, how many demand-side measures can we get into this premise at a single point in time? In order to maintain our grid in Hawaii, we have our island grid, we need things on the demand side to really be working and targeting with what's happening on the grid scale side, which is whether it's wind, whether it's solar, whether it's fossil fuel generation, we need to have things working pretty darn harmoniously in order to make sure that we're managing the grid effectively and cost effectively.

That leads to one additional point. If we are installing photovoltaics on the customer home, it is more cost effective and beneficial to the economy and the customer to do an energy efficiency audit and upgrade to that facility. If we can offer that along with time of use rates, then now we've met the criteria that I identified for integrated demand-side management.

Now, as a regulator, I am in this capacity, after already falling in love with IDSM, to help make this happen. Hawaii is unique. I consider it the poster child for challenging barriers for doing IDSM, because we have a public benefit fee administrator that is responsible for executing our energy efficiency programs and helping us meet our energy efficiency portfolio goals. Then we have our electric utilities that are responsible for DER and DR and our advanced rates. So, they're not even in the same building, and sometimes there might be some points of contention of stepping on toes, and that can be really challenging.

So, what do we have to do as regulators? Well, one of the options in our toolkit, and this would be applicable to a utility that also has silos within it, is to offer performance incentives for collaboration and coordination that are imperative for the success of this program. Performance incentives are very effective in getting things done, in particular on the customer side.

Another really big important factor is that regulatory IDSM programs are also siloed. On the regulation side, we have special analysts that are focusing on energy efficiency. We have one focusing on demand response and also one on DERs, and they're in separate buckets, and we're considering the programs and the portfolios separately. That is mirrored, obviously, by the programs within the utility or the program administrator. So, we don't have silos in just one location. It's actually at the regulatory level as well. That has to be addressed, that has to be fundamentally... It has to almost start at the regulatory level in order for it to be passed onto more of program administration, because we can't offer evaluation and valuation and we can't design metrics without starting to think of these as a collective, comprehensive package that we're trying to accomplish.

That leads to really what gets measured is what gets done. How are our metrics encouraging IDSM? I know that in Hawaii, we have first year kWh savings. That worked great 10 years ago, but it isn't meeting the objective that we have today in Hawaii, in order for us to meet our policy goals or even to serve the customer in the most effective way. So we need, and we are, working on those metrics not just at the program portfolio level with the program administrator, but we're actually re-evaluating the energy efficiency portfolio standards at the state level to just say, hey, are these still in line with our policy objectives today, since we've now adopted carbon neutrality, or we've accelerated the renewable portfolio standards, since we've had such a high adoption of photovoltaics and electric vehicles are coming online?

Things have changed so much over the last 10 years and they're changing so quickly now, that we have to stay on top of what we're actually encouraging in the industry. Then, that leads to the last bullet, which is really making sure that our program is matching and our metrics, and what we're asking for matches the societal goals and the public interest.

Patterson: Our first question is for Jenny. Thanks so much for outlining some of the barriers from a regulatory perspective, and some potential solutions. We had a few questions for our panelists around silos, in terms of funding streams across these programs, and also in terms of cost effectiveness. I'm wondering, how can program administrators or utilities work with regulators to help overcome these barriers? Do you have some insights related to funding and cost effectiveness aspects associated with integrated demand-side management?

Potter: Absolutely. This is something that we're currently tracking and tackling right now in Hawaii, and I'll get to the punch line later, I guess. But what we've asked is that the public benefits administrator... They wanted to do a triennial plan. They were on this annual plan, which was not really helping and effective, and I think actually George had mentioned, oh, we only got a year, and it just kept being the status quo. Yeah, really thinking about implementing and doing the types of programs that you want to do over a longer period of time allows for that innovation.

We asked Hawaii Energy to go to the drawing board and be as creative and get out there as much as possible. Be as innovative as possible. We also revisited the statute in Hawaii that established the public benefit fee administrator, and said, what does this clearly say? It says demand-side management, and it never specifically said energy efficiency. It said using demand-side management to meet the energy efficiency goals. But it was really like, we could play with that a little bit. Demand-side management is obviously more than just energy efficiency.

So go ahead, break out of the traditional role, and start thinking about how you can do with demand response, and what would you do with an electric vehicle rebate program, and how would you consider doing loans or partnering with our low income photovoltaic loan program, partnering with them to do energy efficiency upgrades?

So, we asked them to really get outside the box. We didn't say that we'll approve everything, but to bring us your best and your brightest, and then we'll look at the costs. But don't start with the cost first. Let's start with what the grid needs. Let's start with what the customer expectations are. Let's start with our public policy goals, and really then start thinking about what makes up a program or what that would look like.

That did lead to some questions of, well, the value of this energy savings is... Well, the cost of energy savings is actually increasing, because we're doing things that are more innovative, that are more expensive, maybe even doing hard to reach populations. So you have to accept that and say, well, what is the cost effectiveness threshold that you've established, and do you want to evaluate it at a portfolio level, do you want to look at it on a programmatic level overall? Then the third question that comes in is, how are we going to evaluate its effectiveness? Those are all things that we're working on right now, so nothing is set in stone.

But the idea was to flip this on its head and say, okay, define what is cost effective, and put that out there as a ceiling, and say whatever iDSM falls below that, and that's what we're going to go for. This was more like, what can we do, how can we integrate more, how can we deliver more to meet the grid needs, the societal goals, and the policy objectives? That had to happen at the policy level. It has to. If it doesn't, then it's going to fall on deaf ears.

Patterson: That was a really comprehensive and interesting response to that question. You touched on all aspects of cost effectiveness, measurement, goal setting, et cetera. I think one follow up to that is, I think, conceptually, we assume that by combining programs where there's EE plus DR plus rates, or VD plus ER plus EE or whatnot, the costs go down and the savings go up. But is that really the case, and does it really depend based upon what ultimately... how we ultimately assess cost effectiveness and measure those integrated programs?

Potter: I think it's the latter. In particular, what we found... Hawaii is a pretty small market. We've saturated a lot of the market with lighting, and that puts us kind of at a precarious spot. Lighting was always this, yay, we do lighting, we get all these savings, it's really cheap and it makes everything else look really cost effective as long as we're looking at a holistic package. So, yeah. I think that to your point, it's going to be more expensive. We know that it's cheaper to deliver things at the same time, a single truck roll. Or if you can find technologies that can do more than one thing, which is like a smart thermostat, which we talked about earlier. Those are the most cost effective ways to roll these out.

But ultimately, yeah. It is going to be highly dependent, and that will depend on a lot on the demographics. The location of where customers are sited and where you're focusing what types of programs, they should reflect the value that those types of programs provide. They might be more valuable to implement over on the south side than it is on the east side because of grid conditions or grid constraints. Even though it's the same package or portfolio, it's different in how we actually value it because of the location, or the time that it's delivered at that specific facility.

Similar to the types of demographics... We've talked a lot about data, George and Denise did, and in the valuation of these things, it becomes more complicated. We have to accept that because we can't just say lighting was really inexpensive and it was the best way to go. Now that we're going deeper and we're getting more complex with the programs and the types of offerings, that also comes with thinking about the customer demographics, where they are on the grid, how we're serving them. That becomes central to how we value these types of programs.

Mullen: Let's bring this down to the ground level and look at what some of the utilities are doing. Denise, I want to start asking you, what approach and roadmap are the utilities following to implement IDSM?

Kuehn: That's part of the complexity, right, because now, really, in order to optimize all these things going on, we have to cross over roadmaps. We have our demand response roadmap. We have our demand-side management roadmap. IT has a roadmap; T&D has a roadmap. So our steps really is, in our last roadmaps, are starting to cross over to these other departments, and try to create more inclusionary visions of how all these systems are going to intermix, because that's the only way we're going to truly get integration of these different services, is to be working together to make sure our priorities are aligned. That includes the customer care roadmap.

Mullen: How are the various departments in your utility aligning these efforts and breaking through the silos that had existed previously?

Kuehn: That's part of the opportunity, excuse me, the strategic plan has helped in order to set that direction, to pull it together. Different people have helped pull that together, because it truly is not innate in the utility industry yet. All of them are siloed, so we're pulling people together to hit that common goal.

I think a piece of it too is the value stream. As, across the utilities, our decisions are becoming more and more customer-centric, since the customer hits all of these pieces from the technology and the customer care and the independence and the privacy and the IT aspect, and then the delivery of the actual product, then it's pulled together simply because the common root is the customer.

I think a piece of that, and this is the challenge where I see the industry going... We talk a lot about cost effectiveness tests. When you really start peeling it back, they're numbers. They're numbers based on assumptions of avoided cost, of the value of demand response, the value to the customer. I think that as we go forward, we're going to have changes on how we identify and prioritize these programs, shifting from what we define as the DSM cost effectiveness test now, to more of that overall value, and that we start as an industry further defining a foundation for standardization of how we calculate some of these numbers and an assumption on the impact of the environment, of the cost of generation, of all of these different attributes that up to this point have been very utility-centric.

Mullen: By combining programs, do you see these savings, costs going down and savings going up, or a reduction in both cost savings and spend?

Kuehn: That's where I think the integrated piece comes in, right, because now if you can truly integrate and have common platforms, you reduce your overall cost of IT, of staff development, and the service to the customer is it's a much more consistent experience. That's the part about integrated that is very important. The integration allows you to pull back this data from all of these different services, and being able to take that holistic approach to, how do we optimize this portfolio for our customer and for the utility, in which to streamline processes, automate the experience, so that the more programs you have, they just build on each other.

For example, we're up to roughly 30 programs and proof of concept evaluations, and we've been able to automate and standardize over 22 of them. The key is four or five years ago, a lot of it was still on spreadsheets. Then you couldn't look at the overall customer perspective. Right now, we're adding the buildings for both single family, multi-family, and commercial audits. We're putting that in the system. We're putting in the information from the property tax ID from some of the different low income entities, some of the 501(c)(3) criteria. So, we will truly have a 360-view of the customer, their usage, and we can then customize the programs that will fit what the customer needs are.

So we're on that path, and we're probably 60-70% there. Within a year, we should have 80-90% of it all in that centralized spot. I think that's going to help us decrease the cost and increase the value to the customer.

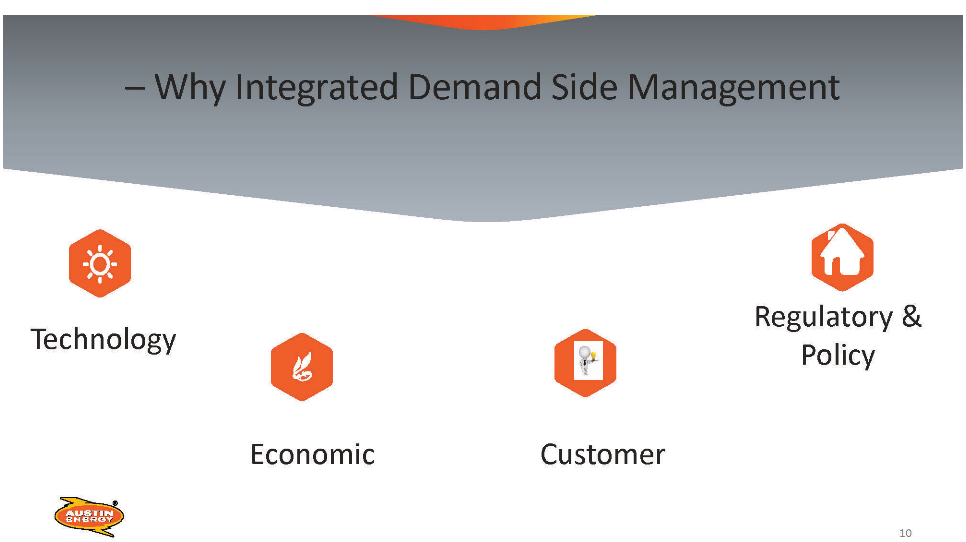
Mullen: George, how is Xcel dealing with all of this, from the roadmaps and approach through to the cost effectiveness and silos?

Beatty: I'm hearing a lot of the same words from Denise and Jennifer that I hear in the halls of Xcel energy here. A 360-view of the customer, focusing on the customer experience. Those are all things that we are really embracing and implementing internally here. We are doing everything we can to focus more on the customer experience, rather than individual products, which traditionally DSM programs have focused on. They focused on a motor product or a compressed air product. But we're really trying to look at how we can give the customer a broader package that really drives up their satisfaction.

The struggle is, what do the statutes allow us to do? Our approach has been more to try and push the envelope a little bit from a regulatory standpoint in a very respectful way but introducing new ideas. I talked about our Big Tank filing. We knew when we sent that in that there was a chance that it might not get approved, but we knew we needed to start that conversation with our regulators, and mission accomplished. They established a committee to further that discussion. They rejected it, but they said, we want to talk about this more, and we need to explore these topics.

So I don't think utilities can sit around and wait for their regulators to tell them what they can and can't do. I think they need to start those conversations and maybe help educate their regulators a little bit, listen to the interveners, and involve everybody in that roadmap process. I know for a lot of our DR products, when we are going through and doing regulatory write ups, we say, in the stakeholder process, how does this satisfy the key topics in our stakeholder wants and needs? It's not just focusing on the customer, but it's trying to find a way to revisit the statutes so we can facilitate those products.

Patterson: I wanted to ask a little bit about specific integrated program offerings. When you're trying to pull together a suite of integrated demand-side management efforts, are there particular markets, such as residential, small to medium business, or large C&I customers where this works, or are there particular types of programs, like traditional direct install programs, or more behavioral energy management types of programs that may be more germane to this type of model? Or does it matter? That's for any of the panelists.



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Beatty: I would say we're going to find out once we start to introduce these types of products. My gut tells me that residential is going to be a really big market for these integrated demand-side management programs. I talked about thermostats because it provides a lot of different values to the customer. It provides an ability to lower their bills. It provides them value. If you're a technology geek, it gives you a certain satisfaction, having this shiny thing on your wall that you can also interact with from your phone. But I really don't think we will know what the best markets are and how markets are going to react until we really start to introduce these products and how we deliver them and see what the reaction will be.

Kuehn: I think what we've seen here in Austin, and keep in mind that we have a lot of tech companies that are very focused on sustainability... So, the Googles, the Apples, some of those bigger companies, they find value. Even though it costs them more, they assess the aspects as a huge value to help them deliver these services to the customer that align with their mission. So, I see that piece as being the ones that we've had the most success. The challenge with that is also the long budget line. You really have to have some good relationships and a long-term for that.

Kuehn: The second one, as George has mentioned, I think residential is a nice complement to that, because an individual can then do it for their whole home. We have some that have done it to that extreme, of building all of these together. It's our job as a utility to give them the opportunity to pull all those together and provide them that education so that they know what is accurate and what you can actually accomplish, and what you can't. One of the key pushbacks that we've seen is people will put in a solar panel and expect it to take away all their bill. When they haven't done energy efficiency in their house, then what they're finding is they're not saving as much as they had anticipated. So, helping educate those customers that all of these pieces come hand-in-hand, if you really want to optimize the return on investment or the value to you.

Patterson: We had a question from the audience around the role of electrification in integrated demand-side management, and Jenny, I hope this is okay to ask. But you originally started with the definition of integrated demand-side management, and it sort of reflected all types of ways to manage demand. Do you have a sense for where that might fit into the definition that you produced as part of your paper that you wrote for Lawrence Berkeley National Lab?

Potter: Yes, I do. I think one of the things that I noted in Hawaii... We actually, the utility there put out... The HECO companies put out a paper on the electrification of transportation, which was a great starting point. They beat everybody to the punch, because there wasn't a whole lot of publicity around electrification of transportation in particular. But when the governor signed the bill for net neutral carbon emissions, that was really when everyone said, okay, we're going to have to take this pretty seriously, because that meant that we were electrifying our transportation sector. There's just no way to go about that without doing that.

We've worked really closely, and we've created an excellent relationship with the California Public Utility Commission in looking at some of the challenges around electrification. In the case of California, as we know, they have a lot of natural gas usage. So, they have a very interesting and challenging future ahead of them in trying to really change the carbon footprint of their building stock. But that is what's interesting about that in particular for all of the rest of us, is California is such a huge market player. As they start looking and adopting and moving the market to make these buildings more flexible, more electrified, that are more responsive, that is going to move the market for the types of technologies that are available for us.

I do say we ride the coattails of California, because we have a lot of similarities with them. But we're thinking about what that's going to take. In order to make buildings the most effective and efficient, electrification, when you think about it in Hawaii, because we don't have that natural gas load, we don't have heating load, we need to make them flexible, essentially. They're going to have to be pretty flexible. The idea of the electrification falling within the electric vehicles piece is really, I think, the only way that I've really managed that at this point within the DSM spectrum that I identified with those six components. But that's still definitely an important one.

Patterson: As we wrap up, we have a handful more of minutes. It would be nice to have each of the panelists talk about next constructive step towards implementing integrated demand-side management, or any sort of words of wisdom or advice that you might want to offer to the folks on the phone.

Beatty: I would say you have to make sure that you have, as Jennifer said, that you have to revisit statutes and make sure that you have the architecture in place to make these things happen. If you don't have the rules and the regulatory structure to make these things happen, they're just never going to happen. I think a key next step is working closely with your regulators and interveners and educating them on the value of this and working towards a solution you can all agree with.

Kuehn: To build off of what George said, that's what Austin is doing, as far as... We've done several proof of concepts, and we've integrated more and more of these options within our programs, and we are doing more outreach and education so that we can help customers identify what fits their needs, and we're just building on that from all kinds of challenges. From inside retail stores, so at the point of sale, they can make decisions, to school-based education and the kids, so they can work with their parents and change their home perspective of it. Then obviously, our traditional programs, just so that people start understanding what these different options are, and how it might impact them.

Potter: The only thing I would add would be to continue to be innovative and flexible in your program design. Don't get rigid about what it needs to look like and the components it needs to have. Make sure that there's flexibility to say, okay, we can bundle this type of technology with this type of technology, because that might work for this demographic. We've become so seasoned and we do lighting retrofits and that's in this type of bucket, and then my experience with the utility, that's how we had programs this way. There was a pool pump program, and there was a thermostat program, and now we really have to think about how they're all going to be able to work together, kind of like going shopping and picking out a different group of vegetables and fruits. That may be very different for every person.

Then in addition, in working with your regulator, propose pilots. I haven't met a regulator yet that's like, I hate it when they bring me pilots. I don't want to see anything innovative. That's always an option, to bring forth either transmittal or an application or something that is looking at these types of opportunities. Maybe it's only sector based, it's commercial or it's low income. It doesn't matter. But I think that George, you brought up the point that even just bringing it to their attention is going to be helpful, because they're not going to necessarily know what they're missing until there is an opportunity for them to start considering it.

So maybe it's shot down once, maybe it's shot down twice. Keep trying, keep going up to bat.

Presentation slides available at https://bit.ly/2GhS7l8

Load Flexibility Potential in U.S. by 2030

From Load Management Dialogue

Ryan Hledik
The Brattle Group

Richard Barone
Hawaiian Electric Company

Richard Barone: Thanks everyone for joining us for another edition of PLMA Load Management Dialogue. My name is Richard Barone. I'm the Director of Demand Response at Hawaiian Electric and I'm joined today by Ryan Hledik of The Brattle Group and Ryan and I are going to sit and discuss the recent report that he and the Brattle Group put out entitled The National Potential for Load Flexibility, which takes a look over the next 10 years or so at the value and potential for load flexibility nationally here in the U.S. U.S. but that said, I'm going to pass it over to Ryan and have him introduce himself and give us a little bit of an overview of this report and what his motivation for doing it was.

Ryan Hledik: It's a real pleasure to have the opportunity to, to speak with you about this new study that we put out on an exciting topic that we're all very familiar with, loads, flexibility. I'm a principal in The Brattle Group, San Francisco office. For those of you who aren't familiar with Brattle, we're an economic consulting firm doing a right, a wide range of, of, of things with, with one of our key focus areas being energy and electricity in particular. Our work in that areas ranges from, wholesale power market design to asset valuation. And there's a group of several of us at Brattle who are focused pretty heavily on the demand side and various aspects of the utility industry that deal with the end customer.

When I joined Brattle 13 years ago, I started by doing a lot of work on smart metering rollouts and all of the exciting new demand response and retail pricing and energy efficiency programs that smart metering would allow utilities to offer to their customers. That work has, has since evolved into areas related to, you know, load flexibility, market potential, for example, and retail rate design and issues related to the integration of distributed energy resources. My personal focus has been on a variety of aspects of the demand side with demand response really being at the core of that work. And just to give a couple minutes then of background on this study in particular and the reasons, the reasons we decided that it was, it was time to put out a study on the national potential for load flexibility.

I was part of the consulting team that that lead a study that many of you are probably familiar with. It was first National Assessment for Demand Response Potential and that was something that we worked on around 2008. It was published in 2009. We've now reached in past the 10 year anniversary of, of that study, which estimated DR potential at the state level for each of the 50 states in the U.S. U.S. plus D.C. And a lot has changed since then in terms of how we think about demand response. You know, that study was focused on how we can get to a point where we're significantly reducing the bulk system peak demand. What we're seeing is we're starting to think about demand response very differently. Now we're thinking about it as load flexibility and that means not just reducing our system peak, but also geographically deploying demand response programs to avoid the need for specific transmission or distribution projects or managing load to provide around the clock fast response, ancillary services or managing load and other ways to integrate renewables by addressing issues related to the duck curve and things like that.

We saw this transition happening in the demand response space and, seeing that transition that just happened to coincide actually with some work that we were doing with Xcel Energy in their northern states power service territory where they were, Xcel was looking to incorporate new load flexibility opportunities into their integrated resource plan. And so, they reached out to Brattle and we worked with Xcel for a couple of years to develop methodologies and approaches for incorporating load flexibility into their resource planning process. That IRP is, is, is publicly available now as filed this summer. And our, our report that's associated with that is available in public. But when we wrapped up that work, and said, you know, this is something that has seen what kind of broader national appeal and interest.

We took the same methodology and approach that we had developed through that work with Xcel Energy and we ended up applying it at the national level. So, what that means is this study that that we've put out, it's, it's essentially an assessment of load flexibility potential "national average" utility where we've then taken those results and scaled them up to the national level. So, we're giving a kind of a snapshot of the types of opportunities and benefits and potential that we would see in new load flexibility programs for the "average utility". I think an important caveat to mention upfront as we get into this conversation is that this is really a study that could have very different results if we were looking at a given specific utility, whether that's in Minnesota or Hawaii or California or somewhere else. So, this is intended to be a high level view of opportunities and insights as it relates to the evolution of the demand response market. But definitely something that I think requires more nuanced discussion as we start to think about how it applies to any given utility.

Barone: I think it's meaningful that the origins of this work were for sort of real life scenario for a real client. A real utility and then the extrapolation and expansion thereafter. It makes sense to me, but clearly refinements have to be applied as you get into different jurisdictions and so forth. But, let's stick to the high level and just to take a little bit of a highlight section here and kind of what I'll call the now and later. In terms of what is kind of the current state of this DR or load flexibility market and how do you see it evolving from the results of your report, what does it kind of portray as the evolution over that 10-year horizon.

Hledik: A lot of us are probably familiar with the current state of the market. Just to give my view of that at a high level, our assessment in that FERC study right now, is that we have a pretty robust, potentially robust portfolio, 59 gigawatts of demand response capability that exists in the U.S. today. And that's mostly focused on reducing our system peak during a few hours of the year. And most of that potential resides in programs that have been offered for decades. Basically, interruptible tariffs for large commercial and industrial customers and then direct load control of residential air conditioning and, and some heating and then water heating as well. So, these programs as they currently exist, they're kind of a one size fits all approach to demand response, right?

For every utility, these are basically programs that are being used or have been used to reduce that system peak. But where we see demand response going in the future is really transitioning to a set of services that are more tailored to a given utility's system needs and market conditions. As you know, the need for conventional peaking capacity lessens but the need for renewables integration increases. Different utilities are going to have you know, different needs for using their demand response programs or utility in California for example, may want to use load flexibility programs to build load in the middle of the day when the sun is shining and there's potentially curtailments of solar, whereas a utility in the upper Midwest may want to use load flexibility to build load during nighttime hours when there are curtailments of wind. So one sort of big theme that I see emerging here is that we're going to be moving as we, as we go forward with demand response programs moving from a case where everyone's just focused on kind of reducing their top system peak hours to using these programs in a more tailored and nuanced way that will really address the specific operational challenges and issues that they're dealing with on their system.

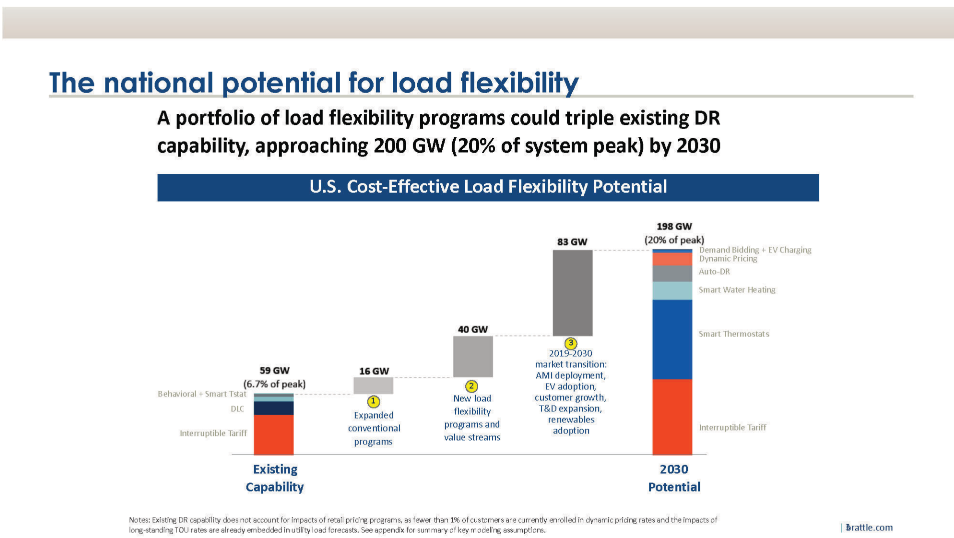
Barone: I want to see what you think about this particular nuance. Somebody hearing what you just said might say, well that sounds good. Can't some of these things be driven through time of use or static pricing buckets type of mechanisms. What I think, in my estimation and observation what went unspoken in what you just said is that very often, there is a pattern to critical peak times, and you frequently need some responsiveness to that pattern. However, if you have the need for load building, let's say in the middle of the day, it may not be the case that tomorrow is sunny, and you may not need that load build at that point in time. In fact, quite the contrary, you might even have suddenly a bunch of load shows up on the system that had otherwise been masked, especially for behind the meter systems. So, it is really implicit that flexibility is not just more services, but more of a refined or nuanced applicability from an operational perspective. The dynamics I think have really increased. I'm just curious about your thinking along those, along those lines.

Hledik: That's a great observation. I think it'll really depend on what the utility needs. As we started to do our research on load flexibility, I was a little surprised to see that. I think over the 10-year time horizon in our study there will be specific parts of the country that continue to need conventional peaking generation and demand response can play a very big role in providing that service to a utility. And that might in some cases just mean basically modernizing these existing programs that we have; doing a better job of marketing time of use rates or, tweaking the incentive structure of our interruptible tariff programs and the way they're utilized so that the customers who are participating in those programs are more engaged.

There are probably little changes that we can make to our existing, fairly simple, portfolio demand response programs that will allow us to get more benefit out of those. But then there's also this second category of, of services that you're describing, Rich, which is how do we use this demand response 2.0 to address these real time operational challenges that are presented by renewables. And so, the question becomes, can you do that through pricing alone or is that really something that needs to happen through automation? And I think where we've landed is there are two ways that you can approach this. One is to set very granular, real time prices and then just let the market respond to those prices. Maybe, that means customers sign up with aggregators or various energy services providers who help them manage their load relative to those detailed pricing signals. Maybe they invest in various smart appliances that, that respond to those price signals. That's kind of one end of the spectrum. And then the other end of the spectrum would be, rather than trying to implement very granular retail pricing signals that make all of this happen, instead it happens through demand response programs where utilities are giving customers simple rates or even fixed bills, but then coupling that with a commitment from the customer that they'll allow the utility or the aggregator to manage their load, and manage it in a way that provides these renewables integration services. So, they're kind of two models then we could see either potentially working in the scenarios that you're describing.

Barone: Agreed. At risk of editorializing I would offer to you and to the audience that it is a spectrum, right? I mean, you've created kind of two versions of possible future scenarios, and I think there is a spectrum and you know, opportunities fall anywhere within that spectrum. But some of what drives the best option from a utility perspective is sort of the criticality of the service and or the, the state of the system. For example, what may be an absolute imperative that Hawaiian Electric needs an event-based mechanism, either through an aggregator or through a program or both, maybe handled quite differently by way of a pricing and sort of an economical behavioral response in another jurisdiction because you have, for example, a larger wholesale market to draw from. And, so the criticality of response is not as, as high as it would be in a market like ours, which we don't have a wholesale market.

So it's very interesting. Of course, the nature of the services themselves, you know, if you run the risk of a distribution circuit being overloaded by a lot of energy export at a given time or you know, that then the need to impose action in near real time is very different than it might be in a circuit that's not saturated. I digress a bit and, and I think I just want to kind of incorporate that thought because these are types of things just from the Hawaiian Electric perspective, we struggle with in real time. But I would take a step back here in light of everything we've just discussed, maybe a little bit of a high level in terms of what is the potential for load flexibility and in that, where does the Brattle Group see the big opportunities.



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Hledik: I'm glad you mentioned that. That is the headline finding from this study is, what is that number for the national potential for load flexibility? What we what we found looking out to 2030, and account for the value that would come from new services that you could get from a load flexibility program, like ancillary services, geographically targeted transmission and distribution deferral, and other types of flexibility benefits like that, and extend the definition of demand response to include emerging programs like behavioral demand response, dynamic pricing, thermal storage, smart water heating programs, these new programs that have really just kind of started to get some commercial traction in the last few years, what we find is that the cost effective potential nationally is right around 200 Gigawatts in capacity terms. So that's about 20% of the national system peak demand to the extent that there is such a thing. And so that's, that's about 200 gigawatts of potential relative to 59 gigawatts of capability that we have currently. So. the question is, what is the decomposition of that 200 megawatts? What could potentially get us from where we are today with heavy reliance on interruptible tariffs and some direct load control to a scenario where we have 200 gigawatts of load flexibility. There's a lot, there's a lot of detail on that in the report. I guess there are a couple observations that I'll make for the purposes of the discussion here.

The first is we see a lot of that potential being in the residential sector. In contrast to what we have today, which is, maybe 70% of our existing capability coming from commercial and industrial customers, we're really seeing the growth of adoption in smart thermostats as being the gateway to managing residential customer demand. We've seen as being the challenge with the residential market is that you just have to knock on a lot of doors to get real customers recruited to sign up to participate in these programs. Whereas with large commercial and industrial customers, you can get megawatts of demand response from a single customer. But once you get over that hurdle of customers and they're already installing, smart devices–smart thermostats in particular–in their homes for reasons that have nothing to do with demand response and all you have to do is essentially get that customer to agree to unlock one of the features that their new investment has, and get paid for it, we see that being, the biggest growth opportunity in terms of load flexibility potential over the next decade. And that drives a significant portion of that 200 gigawatt number that I mentioned.

Barone: By the way, there's probably demand response program managers from utilities around the country listening in with thought bubbles saying "all you have to do" is get those customers to do join a program. But, you're right. I think in the advent of smarter thermostats and the evolution of the bring your own device type of programs, I think we all, collectively as an industry, are working on overcoming that friction and overcoming those hurdles. So interesting point though, because you know, I think one would think off the cuff that you go for the bigger loads. You go for the commercial stuff that's a lower hanging fruit, more bang for the buck. But you guys don't tell a different story here.

Hledik: I think saying that it's easier to get those customers is maybe being too generous. Maybe the better way to put it, is that it's less difficult to get those customers to sign up once they have smart thermostats installed. There definitely are all sorts of implementation challenges that come with achieving this potential. But we do see that self-install as a pretty significant opportunity and improvement over the current situation, which is going out and having to install all sorts of technology behind the customer's meter.

Barone: Folks may be reading the report and wondering things like, Hey, could you talk a little bit about some of the challenges in quantifying the potential of this flexibility and how did you go about developing your assumptions? Was this an empirical observation database? Were there other inputs? Cause it's not easy to cover as broad a set of technologies and potential as you guys have done. So maybe just address some of those, some of that experience.

Hledik: I will try and keep it brief cause this is obviously a topic we could spend a lot of time on. But we basically had to develop, a lot of demand response, potential studies for utilities and commissions over the years. And we basically had to develop a new model to address some of these challenges that come with quantifying load flexibility potential and opportunities more broadly. Among the many challenges of doing this and quantifying it, there are a couple of key methodological considerations that I'll mention that I thought were particularly important. One is, when you talk about using load now to provide ancillary services or to defer the need for specific transmission or distribution upgrades, it's really important to take into account the depth of the need for that service.

When we were just talking in the past about using demand response to provide cogeneration capacity value, typically we're looking at demand response portfolios that were smaller than the amount of total amount of peaking capacity that the utility needed. So this wasn't really a consideration, but now what we needed to do in this model was take a pretty detailed look at exactly how much the utility will need in terms of frequency regulation or how many high value transmission and distribution project deferral opportunities are there over this five- or 10-year forecast horizon. We had to think and look very specifically at the role that load flexibility could play in not only providing those services but we also had to look at the extent to which those services could become saturated with load flexibility value before you sort of maxed out on the availability of the resource.

That depth-of-need is one really important consideration to consider. And then another one is this concept of value stacking that comes up a lot when we talk about battery storage and the possibility for say, a smart water heater, to provide not only daily load shifting but also, ancillary services or–depending on the location–even some of those T&D deferral benefits. So, accurately accounting for the ability of a single program or a single load or end use to provide multiple value streams and not double count those benefits and account for operational constraints was also something that we had to model really carefully. I guess to answer the second part of your question, we did that partly based on a review of existing programs, whether those are full scale programs or demonstration projects or pilots that have been offered by utilities around the country and even internationally. We basically developed a database of the findings and results of those programs. Some of it was based on a bottom up modeling and some of it given the emerging nature of some of these programs was based on a review of theoretical academic literature on the ability of these programs to offer these services. It's really a mix and we filled in the gaps with empirical data where wherever it was available. And that was ultimately how we ended up at the conclusions in the study.

Barone: We lived something similar back in 2015 where we did a DR Potential study here for Hawaii. So, I'm familiar with what the weeds start to look like and that double counting issue and value stacking and that could be a whole other conversation that would put a lot of people to sleep. But it's very, important. And when you start to get into the real world application of this flexibility and you understand the operational challenges that may emerge, it's very important to get that assessment as correct as possible up front. Because you don't want to wind up in a situation where you've secured what you think are reliable resources for operational pursuits, only to find out that, oh, this was actually double-counted and we can't use it for this. Bad spot to be in.

Kudos to you guys for taking a hard look at that and doing your best to pencil that out for this study. But it does lead me to a little bit of a discussion. We're running short on time, so it's really two last topics if we can get to them. The one has to do with technologies in general and then maybe we can wrap up with high level conclusions. We want folks to read the report– I'm just telegraphing that now. But in terms of technologies, we've got a few questions to end with–what are the best water heater programs, and generally a question about what other uses you're talking about. And I think you've addressed that a little bit with thermostats–in particular smart thermostats–maybe making up the lion's share. And maybe I'm reading into too much into the residential segment, but we have two very specific questions. If we can talk about water heaters, that'd be cool too. But I'm very interested in what role, if any, do you see energy efficiency playing? It doesn't typically, categorically fall as load flexibility, but I'm wondering how you guys consider that and then I want to ask you about batteries.

Hledik: I'll preemptively answer both of those questions at once and just spend a minute talking about kind of how we define the scope of this study. When we talked about load flexibility in the context of this study, what we're really talking about is management of the customer's actual load–reduction of that load when it's needed during times of high demand and increases in that load during other times of the day. But it's focus was specifically on load management. Basically by definition, that excluded the potential impacts of onsite generation, whether that's from a backup generator or rooftop solar or from a battery. And that definition also largely excluded any sort of energy efficiency program. Because we were focused specifically on dispatchable resources that allow you to actively manage load as opposed to say, overall reductions in energy consumption. But I think, if we were to extend this definition and say, change the terminology from demand response to distributed energy resources more broadly, that in itself is a very interesting and challenging. But a really interesting and useful question to answer. What does this potential start to look like? Or what do the benefits start to look like when you broaden the definition even further than we have to include behind the meter generation, storage, energy efficiency more broadly, things like that.

Barone: Again, sort of Richard Barone's soapbox for just a minute. We hear in the way we've approached this in Hawaii is to look at a whole slew of assets that sit behind the customer's meter–anything really that's controllable or engageable from an energy perspective–is a distributed energy resource. And the lever by which we manifest that control and response to a grid need is a demand response, right? So, it's really the action that we take and by virtue of the fact that we've got 70% of our new PV systems are coming paired with battery storage to us, you know, that that battery has become truly a load flexibility mechanism, right? And yes, it's not self-generating. It is typically deriving its power from the PV systems, but it creates this behind the meter bundled flexibility to allow for the maneuverability of the load. And in combination with the PV, it's actually ultimately reducing the strain on the system as a whole. But, you know, I would be curious to see kind of generation 2 of load flexibility as populations of batteries hit the market. What does that do to the 200-gigawatt number I recall you mentioning. But maybe that's food for thought for the next wave of this investigation and maybe as populations of batteries continue to grow as well as electric vehicles, you might have a different lens and we'll keep that conversation active.

Hledik: I think as a consultant that it's my job and my duty to point out that that would be a great extension of this study if there are utilities or commissioners that are interested in doing it.

Barone: There you have it, a very soft sales pitch to all listening ears out there. Iin closing, to the degree that you're comfortable sharing and maybe piquing people's interest rather than handing it to them on a silver platter, the study concludes with three predictions for the next decade. I'm wondering if you'd be comfortable giving us those highlights as your parting words.

Hledik: I think we've touched on two of them already. The first prediction that we see going forward, even though commercial and industrial customers have accounted for the bulk of demand response capability historically, we're predicting that growth going forward in the demand response market will be larger in the residential sector than it will be among C&I customers for the reasons that I've mentioned. So that's the first one.

The second prediction is that programs are going to get smarter before they get bigger. So, in other words, the first step in this evolution to demand response 2.0 and load flexibility is it's not just throwing away the programs we have and starting from scratch with the new portfolio programs. It's taking that existing infrastructure that we have and finding ways to get more value out of it. Maybe that means transitioning customers on a conventional switch-based direct load control program to a smart thermostat program. Maybe it means looking more closely at the way we designed the incentive structure and our interruptible tariffs and redefining that in a way that's more valuable to the system. That's kind of the first step that we see happening as we move into this new era, this new definition of demand response.

And then third, as a closing thought here, I hope that a lot of the growth that we will see in the demand response market over the next decade will come from a regulatory activity that will give utilities and other parties, the financial incentives to pursue these demand side programs and measures as an as an alternative to making capital investments in infrastructure. And I see that being a really key piece of this–aligning those incentives so that there is a reason to do this as opposed to kind of continuing with the conventional approach of building out the transmission distribution system or investing in generation. Going forward for all of this to happen that's going to play a key role.

Barone: Thank you. And just an observation on your last point. You've seen in certain jurisdictions around the United States pursuits regulatorily of performance based regulation or performance based rate making. And I think that's a primary option for helping utilities to make decisions less influenced by capital bias. I'm wondering if that's the type of alignment of incentives you're thinking about.

Hledik: Exactly. We've started to see more activity in that areas as, as regulators have gotten increasingly interested in demand side options. And that's exactly what I'm referring to is the potential and sort of the opportunity for more of that to happen going forward.

Webinar available at https://bit.ly/38waSxg

IDSM Path Forward

From Load Management Dialogues

Joel Gilbert
Apogee Interactive

Richard Philip
Duke Energy

Richard Philip: Today's topic is integrated demand side management. It is really something that adds on to a conversation that was held back in June. A Load Management Dialogue that was jointly held by PLMA and AESP. And while there's a lot of great conversation and presentations talking about what the promised land is going to look like, what our future is going to look like with that all these things that are going on in our business are moving at a pace that's really been surprising based on my career.

Realistically the path to the future is not very clear and the point that Joel will make is probably not even paved. And so along those lines we get a chance to talk to Joel Gilbert from Apogee Interactive about what might be the things that are going to make a difference to the future of this industry and the things that we can't take our eye off as we go through this transition.

Joel Gilbert: I'm Joel Gilbert, and Elliot Boardman and I were the originators of the thing we now call PLMA... way back when, before a lot of the mechanisms that all of you have enabled were put in place. And to most people I'm pretty well known as a person who's worked a large part of his career in the energy space on energy efficiency and technology options. I am an engineer from Rensselaer Polytechnic Institute with a BS and MS in Chemical Engineering and an MS in Management focused on new product introduction.

Philip: Joel, when PLMA started wholesale electric markets were really just starting to emerge 20 years ago. One of the reasons why PLMA came about was to help us determine how to interact in that type of world. So please talk a little bit about what the challenges were then, and then how that has changed over time.

Gilbert: Way back when in the beginning, if any of you were there, you'll remember that the ISO's we're just forming. A very large part of the United States was facing this question of demand response and how it fit into the portfolio. We didn't call it demand response back then, we called it peak load management. And the key question at the root of the challenge was, where are the price signals? At that time many of the utilities only had two types of agreements and with mostly the larger customers. Other than that they did have residential load control switches on water heaters and air conditioners even way back when, but they were curtailable options, which means you had the right to hit a switch or they were some form of contractual peak load management, usually in the form of a demand

reduction or some kind of rate reduction, if you agreed to release capacity at a call. In some cases, large customers had switches in the control center, and they could literally drop 25 or 50 megawatts at a time.

Gilbert: What PLMA did under the leadership of many in the industry was to come up with market mechanisms to offer price signals. Earlier on it was mostly day ahead hourly price signals. And that seemed to be the first one that was merged into the portfolio. But as Dan Violette and others in the business soon learned, the ISO's didn't recognize this resource as an offset to generation and a lot of work had to be done in the dialogue between the regulators and at that time it was the system operators, PJM being one of the first to create an ISO. It wasn't easy, and the fact is that PLMA did a lot of that work by writing white papers and appearing before certain regulatory groups to explain that this resource had a rightful place alongside the supply side. It was a lot of work and it was done very well. But it wasn't without some bumps along the way.

Gilbert: But frankly, looking back, we achieved that goal in principle. But then it took almost five to 10 years to truly enable it. So, all of you on the call are right now living with the result and in that best age since then. We should feel good about what we did. But, with all that said, in my opinion it's unfortunately not really going to continue with some major refocus. It's a great illustration of the work that PLMA has done, but it doesn't reflect where the future is.

Philip: So, how that been changing over time Joel?

Gilbert: Well, okay, let's be candid and complete with our review. Not everybody's happy about demand response's success. The first success is that demand response tames or limits price spikes. Not everybody was looking at those price spikes as a bad thing. Generators, frankly, look forward to them as an opportunity to finally pay for the capacity they have placed in the market. What happened was way back when these generators had a reservation charge paid for the capacity. This charge was eliminated in markets and was assumed to be reflected in the market price for power at peak.

There was also a whole series of debates back then on this question of how capacity and energy should be paid. The result was often to force the generators into an energy only market. And so, they had to price their capacity based upon scarcity when the loads were high. And that forced the price up to the point where nobody could feel good about it, even though on balance, if you looked at it, the price seems perfectly reasonable. Somebody had to stand by and then provide that last kilowatt hour and that last megawatt hour should be paid high prices. They were nothing more than the old reservation charge divided by relatively few hours of use. But the optics were terrible.

Gilbert: More recently, with the soft market that exists in the ISO energy market, many of the generators have moved the majority of their capability out of the ISO market and into the old-style agreements with their load serving entities. They are out of the ISO markets completely. As a result, it is very common especially here in the southeast, for the generators to have an "all requirements contract with the end utility" (the wireless company and their customers") where we are back to the old style of a demand charge.

The unintended consequence has been that the hourly ISO market no longer contains the real fair price for the load serving entities. The ISO low hourly prices then show low value and can be deemed to fail cost effectiveness. That in turn threatens the business propositions for the curtailment service providers. Then, we lose the demand response resource completely. This of course can also be confounded by locational marginal prices which may have absolutely no bearing on the price impacts load serving entities experience with the generator supply agreements.

Therefore, you could find yourself with "no economic signal" for demand response because its value shifted back to a wholesale power supply agreement. And, making matters even worse, these hourly demand supply agreements have significant "uncertainty" about when that peak demand will be. In fact, you can't be sure about anything. It will depend on whether there is any hot weather in the forecast or... oops we actually just passed the peak demand for this month... because we didn't think it was going to stay cool for the rest of the month. So, this is a very different style of demand response we're going to have to think about here with these new bilateral wholesale supply agreements. That's one key piece. The other key piece is that with solar increasingly entering the market is shifting the value stream of demand response out of the forward hourly markets and into the balancing market, but let's come back to that later.

Philip: I can definitely identify with what you're talking about Joel relative to Duke's six state area. I'm operating programs and both MISO and PJM and deal with that more robust wholesale marketplace at some level. But in the Carolinas and Florida where we're our own balancing authority in most cases and what you described as a bilateral world is real to me. So, talk to me more about... If the price signals are really coming from the bilateral agreements and not the wholesale markets, what does that mean and what needs to change?

Gilbert: This is where I think we're going to need to form a new interest group within the PLMA that includes traders and other supply risk managers. At the end of the day, if we are going to really influence these bilateral agreements, we need a risk trading perspective on price risk exposures. For instance, it is pretty easy once you get into the heat of the summer to probably set a temperature-based demand response strategy. Meaning that when the temperature gets over a certain point, say 95 degrees here in the Southeast, it's very likely that, that's going to be the peak setting days and hours in the month.

But the joke I always use to express this risk is that you hear ducks quacking in the clouds above, but you don't really see them, so you just keep firing your shotgun hoping to hit a duck. And at the end of the month, if you took enough shots, you probably hit enough ducks to make an economic impact. But the challenge is that it's not a single shot game anymore. It is a trading strategy and it's almost a risk profile strategy. That isn't the way we've structured programs historically to operate here. We've told customers "no more than X events in a month" or no more than Y hours a month. We may need to rethink this.

To try to reduce demand, especially in a month like May here in the southeast (where you may get cool weather and then have an unpredictable heat storm) is going to create problems in customer expectations and communication. Answering senior leadership questions and challenges within the load serving entities about how programs are working and what the benefits are to them is going to become less and less clear, especially in comparison to simple measures we used in the past. We haven't been preparing customers for this world, I think we have a huge communication challenge. I think we have an operational challenge as we move towards this market, because it's becoming more of a risk-portfolio we are trying to manage rather than what I call the single rifle shot approach we've used in the past.

Philip: I'm hearing a couple things. One is, is some of what you talked about this kind of peak chasing type of activity is something that actually happens in PJM today with customers trying to manage the peak load contribution and kind of manage their own demand charge. Very predictive and that type of thing.

But as a whole where you're talking about also harkens back to the utility business when I started, and not the one I've been working in most recently. This is as Yogi Berra said, kind of déjà vu all over again. So, what does that mean to IDSM? How much to change or to deal with this much stronger predictive aspect?

Gilbert: That is a key important question. My short answer is I don't know. Let me give you a couple of different ways I believe the answer might emerge over time. I'm going to go back to my suggestion of an energy trader's perspective. Let's go back to the aggregator that we've all been counting on to somehow find the end use resource and aggregate it. Traders love optionality, and they are completely comfortable with managing a portfolio. You give them an option that they can exercise, and they'll use it when and where they believe it fits. But we MUST create (or originate is the term they would be use) the aggregate into an exercisable electronic option, which is basically electronic DSM... the same thing that California has been seeking forever. But we've got to operationalize it in the traders' perspective, so that they can just pull the trigger and get what they want.

There are many members of PLMA who have really done the yeoman's work here in the past. And I don't want to pick on one because somebody else who's a member who does the same thing, probably will get mad at me, but let's just say there are many of our members who have done this in the old world of ISO's. And the only thing I'm suggesting is rather than rely on traditional ISO's forecasting of hourly prices and things like that, we're going to have to originate another style of operational performance, that is load serving entities' risk trader perspective.

The traders know how to do this. That's their job. They live in that risk world. They have all the tools they need at their fingertips. What they need from our side is another switch to pull. And so, what we need to do create some of this optionality and reformulate our traditional resources into it. It's not that it's a different resource, because it is the same thing we've all talked about forever, but we've never strung it together with a different buyer and seller. That is what origination is all about. We got some heavy lifting work to do.

Philip: To summarize this before we move on, let's talk more about the technology side. What you're saying is the current model, which has been partly driven by the emergence of the wholesale markets and brought focus to real time pricing and some peak level pricing, could be moving back to old style curtailable loads where customers gave us the utility or someone, an operator, the opportunity to kind of push the buttons and control the loads as the power company. And that's pretty big difference–because it becomes more of a probabilistic game. It's about trying to predict where the peaks are going to be and being flexible enough to that you can implement curtailments several times and still be able to engage a volume of customers.

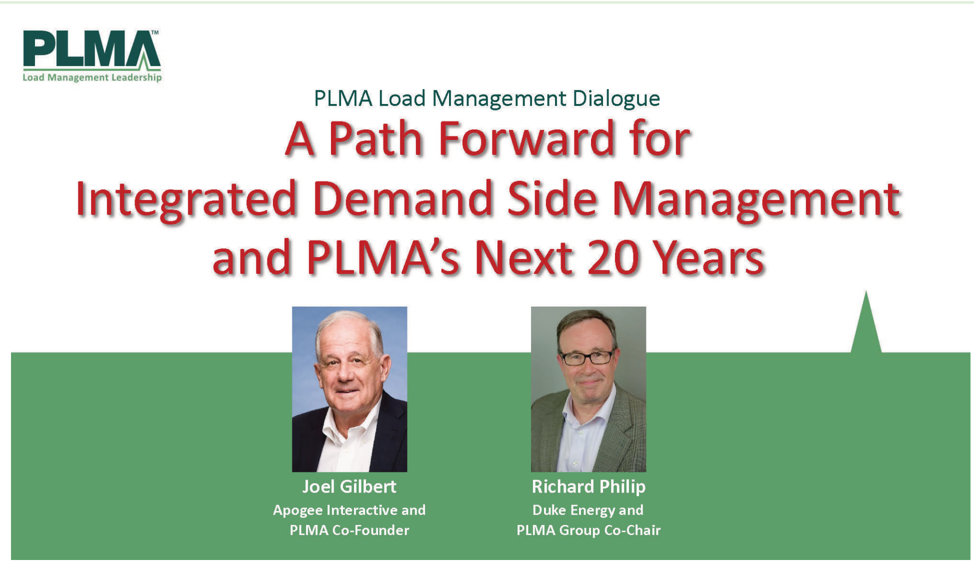
We're not trying to create a world that we're chasing customers away from this flexible resource that we've created over the past couple decades. So, if I follow that kind of–

Gilbert: Let me just add one other little piece. There is one thing we didn't talk about. The shoulder seasons could be a very challenging problem because these peak demand events might not be temperature dependent. They might be dependent on other things. This is another part of the origination puzzle we never anticipated in the old days. Wholesale electricity prices were always low during these periods of time. Therefore, we might have to look for different resources during that month, like controllable water heaters in residential, or some industrial process loads.

I don't want to take exception to anything you summarized but let's not forget that there are a whole series of months that are not going to be weather dependent peaks.

Philip: Agreed. And so, at Duke, we have been experiencing that the shoulder months actually are probably more challenging than the traditional peaks over the course the last few years in some of our territories. Some of that is caused by growth of solar in the Carolinas. Some of that caused by, well, it was the 90s here in Indiana last week, and it was October. That's not normal here, it was weather driven, but still, we've dealt with four straight years now that late September and early October were more challenging than the middle of July in our Indiana, Ohio and Kentucky service areas.

Gilbert: And that's exactly what I think is an important warning about going forward. With more and more solar coming in, these months are going to become bigger challenges to manage.



SLIDE 13 View Slide at: https://bit.ly/30OIGEv

Philip: As I was saying earlier, this looks like the future of controllable loads may turn into more of a probabilistic game going forward. I follow that thinking, this could be great for customers with large controllable loads if we can control them automatically and loads they can go up and down like refrigerated warehouses. Of course, storage via batteries or any storage medium is going to be interested in this idea. It could get interesting for the thing that that's been hot the last couple years around programmable or WIFI enabled thermostats. And as you mentioned, I think the idea of a great interactive water heater fits into this really neatly.

Philip: Let's really move to technology. We all see the Internet of Things trends that are going on and what it might be enabling. But when you and I talked previously, Joel, I think you see special concerns about data privacy and IT and things in that realm. And I will tell you here at the large utility those things are huge. Please talk a little bit more about what you are seeing in that arena, as somebody who works with a bunch of utilities who have a lot of different perspectives. And ultimately, I would like for you to talk a little bit more about what an organization like PLMA needs to do on that front.

Gilbert: As wise people like to say, "wherever there's a problem there's an opportunity." And so, let's talk about the general characteristics within the utility industry of privacy and IT resources. The simple fact is that the IT resources are stretched thin right now. I have never seen a constraint as big as I'm seeing right now within the utility industry on IT resources in the past. They are backlogged... they are so far behind... with years of project commitments ahead.

It has reached the point where it is just disabling. I am not suggesting they are off course. But this then opens an opportunity for a third party or some form of partnership with somebody else who does have the resources the utilities don't have. And I think many of the PLMA members can offer data services and software development around this. Meter companies can certainly offer expanded services. It will take a village as the adage goes. But, without an expanded resource here it is almost impossible to have a conversation about the future, because the person who can answer the question within the IT resources is already so frazzled.

What I would suggest to anybody on the webinar who is in this business, who is an outside agent, is to walk gently here. Because even though you can offer services, opening up the conversation tends to create bristling. It's a very delicate balance. Everybody within the energy utility business is afraid of somebody else using data and breaking some kind of security issue. The privacy issue, which you mentioned is an important one, but I think we can get around that, because we're not trying to share credit information, addresses and things like that, we can use meter IDs and secure things with plenty of protection. That's not the challenge. But even having the conversation can be hard to enable. So, what I'm going to suggest here is that the PLMA members, not just walk softly but try to productize this so that there doesn't seem to be as much assembly required.

It might be helpful to remember my most fearful three words on a present for my kids: Some Assembly Required. I would drag these presents that I had been hiding and see the warning. And that is a real fear in today's utility world... these words create fear and trepidation within many power companies... they don't have time to assemble anything. Therefore, I think it is going to be terribly important that the members of PLMA who can offer services, offer simple packages and bundles to enable some of this, and don't assume they get any IT resource assistance.

Philip: I can agree with that. I think that the more somebody can bring a full solution to a utility at this point in time, the more likely it is that we can get something done. It is consistent with my experience particularly recently here at Duke. So, Joel as you know, the requirements of the utilities and their executives to provide a business case around how all these changing concepts fit together in a way that shows we're really driving to the right place has only grown over the years. It is hard sometimes to get senior leadership on board for the level of change that's occurring and try to make sure they understand what really the ramifications are. How can PLMA help work on that?

Gilbert: You are right. And it is similar problem we had when we started the PLMA organization. Back then we didn't use the term monetized, we just used the term cost justify. It is now the single most common question in the form of a single word, and frankly, we don't have a good answer for it right yet. I think anybody who's in the business knows that the value is going to be high. But unfortunately, at this time, the mechanisms for what we would call price transparency don't exist very much in the balancing market.

When we try to use the forward market for the business case, we don't see a lot of value in it. Therefore, that tends to defeat the business case. I think where we are going will require us to start looking at what is generally referred to in trading is option values. There is a value to have an option. In many ways, these are insurance values. Most of us must insure our cars. The energy industry is just now beginning to learn there are new risks and costs.

I think we need to have this subject area expanded within the PLMA... talking about some of this as option values and we need to begin an active conversation about this right now. The clues are there in the balancing market already, especially in areas of the country with large solar resource development. So, let's start there and discuss option values traders are currently using there or think have value and I think we can get clues about what is going to be future DR and DER value propositions.

However, the balancing market represents a new world to many. It is generally not transparent. It's tricky... it's complex. It varies around the country, but I do think as an organization, there's a lot of helpful dialogue we can open up here around that, especially ramping. I believe ramping is going to really have some high DR and DER values.

Philip: I agree. So, with that, Joel, you've spent some time talking about a trader's perspective and talking about the insurance optionality/risk valuation type of thing. My gut instinct is that PLMA either needs to find some new friends or bring some new people at the table in order to help us work through this because while we have members that have exposure to a lot of those things, that's not what our day jobs have been.

Gilbert: That's correct. It's a new group of people who frankly, we probably need to invite directly and personally. I don't think they'll have any reason not to show up either. I've talked to some of the larger trading organizations like TEA–The Energy Authority–who operates in the southeast. These are fabulous professionals. I frankly just don't think we've reached out to them in the past because it wasn't clear there was a mutual agenda, but I do think they would agree that this is now moving closer to mutuality.

Philip: Okay. That helps. Any other thoughts about others that we should be reaching out to?

Gilbert: Well, the trading organizations sometimes exists within the utilities themselves, because they're trying to come up with agreements and value them. So, I think we may have more friends than we think inside the utility, but they're buried in a different organization than we typically talk to. Remember we're focused on typically the customers, the "load", and then the people who work with them both.

Philip: I agree. And I was thinking of some of those people within my own company.

Gilbert: I think this is going to be a very healthy and lively conversation. Traders love optionality. We have resources, but we just need to know who we have to originate them into the trading frameworks.

Philip: And some of these guys, I have built relationships with over the years, and now we're talking on a regular basis. I can pick up the phone and deal with some situations directly. And literally, I was in Charlotte last week when things were getting really hot across so much of the eastern half of the country (at time when Fall plant maintenance is supposed to be beginning) and I walked right into the regulated trading floor to talk to them explicitly about what we need to be doing in preparation for potential of PJM events. It's not like they're unknown to me, it's more about taking the next step in this conversation.

Gilbert: As a matter of fact, what you just said would be a great panel for one of the upcoming PLMA meetings. Let's talk about the optionality that both sides are looking for. There will be many members of PLMA who would find our collaborative and collegiate forum refreshing and productive. We need to have candid conversations at the nub of this issue and the challenges of moving forward. Once again, those facing significant solar resources, especially in the East where we have intermittent cloud cover should be especially interesting.

Philip: Here's another topic, Joel, that jumps out to me here. What about the way decisions are made today? It seems that this industry is no longer being driven by visionaries as it was 20 years ago. My old CEO, Jim Rogers, would plant a stake in the ground to try to challenge the way people were thinking in many cases. And sometimes those ideas were popular, sometimes not. But today everything is focused around teams, and it was just an awful lot of group think, as opposed to the kind of seeing those visionary individuals. So, how do we deal with that?

Gilbert: There has been such a focus on being politically correct today, that nobody calls a spade a spade. The sense that everybody must agree disables truly creative conversations and significant change. You get gravitation towards the mean. So, I would suggest we need to be really careful who you put on these teams. Make sure they really do understand the issues, understand where we've been, and comprehend the seriousness of the need to change. Otherwise these individuals will disable the team because either you can't get them up the learning curve fast enough, or they, frankly, are just not going to get it. And so, I really think team size needs to be small and tasked with coming up with something. Otherwise, teams today come up with no answer, and in my opinion that is team failure.

This is why I believe people should be active participants in PLMA. It is the collegiate and collaborative nature to the conversations at PLMA. Almost everybody who shows up at these meetings is starting that pretty high level, and you can have meaningful dialogues.

Frankly, I think one of the challenges we are all going to face is that finding solutions to the portfolio of the future is going to be trying a lot of things and see what works, what doesn't and why. I don't think I could sit here and tell you what the one answer is on anything anymore. I think I could tell you where I would put a chip down on the table that probably will play. But I will tell you, it's not a single stack of chips. We're going to have to learn as we go. Therefore, you have to be comfortable with portfolio approaches. And portfolio management is a very different thought process than trying to answer a go, no-go question on any one idea.

Philip: Yes. Agreed. Very much so. I have a few questions here from the audience Joel. One person makes the point what about the role of regulators? In some states, they have been visionary. We see things going on in New York and obviously Hawaii being forced at some level by some of the uniqueness that goes on there and there's always something interesting and new going on in California and some of the other markets. But clearly regulators fit into this picture as we go forward. And in some places my experience is they can be a help but help lead this change. In other places, you're going to have to lead it.

Gilbert: We're no longer living in an easy world. The one thing that I believe is central to not only PLMA, but to life itself is dialogue. If you've got a place where you can express a thought and you can have an interaction with others who either support or have an alternative way of thinking about the same thing, then we all learn something. I like to say there's no bad ideas. There are some ideas that will work in certain situations and not work in others. And given the regulatory landscape across the country is so varied, there's not going to be one answer here. However, not talking to regulators and assuming they're part of the solution will be costly, because they're ultimately in charge of the decisions in some respects. I am so tired of hearing utilities express fear over talking to regulators and their staff. Talk. Dialogue. Then chip away at the misunderstandings and fill in the gaps on answering the monetization.

If you can't have a conversation with somebody who disagrees with you and be civil and diplomatic, then you're not going to get anywhere. A little humility here would go a long way. Ultimately, this is a cost recovery game. Regulators can cripple you even if you are right, because they just don't like the way you approach them. They can kill you at the cost recovery table. At the end of the day, let's recognize they have that final say and respect that. Help them see the risks and the rewards. There is no single rifle shot that's going to put this all to rest. It's going to be a very interesting. I'm concerned we are not working on the problem actively and the world's changing around us very quickly. So, I don't think we have a lot of time left to get it right in this new world.

Philip: I appreciate that statement. Joel, I had a question that came a little earlier in the conversation. I think it is about this kind of trader's mentality approach to doing things and becomes a question of where do we get the pricing signals, when so much of the change is happening down at the distribution levels? Is this the type of thing where some sort of DSM is going to be needed to try to help that trader or is it really going to be kind of the old fashioned bilateral world?

Gilbert: I don't know if there's one answer the question. I think we're going to see all of the above as they like to say. I think you're right. I think we're going to see people because of the uniqueness of their situation. Hawaii is a perfect testbed for getting this right because they got nobody else that can bail them out. They've got to get this right. And there are other situations around the country where we're going to see some really interesting pilots and projects. And what I'm hoping is those people will come to PLMA, present what they learned, which some cases maybe, oh my God, that's ugly, or wow, here's an answer, we didn't realize it was going to work as well.

Gilbert: Ahmed Faruqui and I are speaking on the question of rates and transformation of rates at the next PLMA meeting. My tongue in cheek contribution is a rewrite of the Dr. Seuss book Green Eggs and Ham. Public attitudes around rate transformation follow this book pretty closely. When I read that book to my kids, they all enjoyed it because it was silly. At the end of the day, what we've got today, frankly, looks a little silly to me. We've got to work on it. And that's part of the reason why I think the PLMA is such a powerful organization.

Philip: I had another question come across as we were talking about the conversations with traders and stuff, I think I'd like some clarification, make sure we're not confusing people. Yes, we recognize that there's FERC rules out there 888 and 999 in some places where transmission information and so forth cannot coarse. I think what I heard you talk about Joel was more of the discipline, the thought processes, and thinking same thing, but it's more almost the attitude and the tool set that a trader needs and be able to apply those into what this next world's going to look like. Is that true?

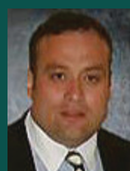
Gilbert: That's exactly right. Perhaps I am not being careful to define what I meant. My point here is that to have a trade execute (which means you pick some option that is going to mitigate or somehow offset some other options you had) somebody has to package it for the trader. The trader is not going to go to make 20 phone calls to 20 large customers to try to get something to happen. Somebody has to operationalize that. And that's the role of the aggregator who takes their portfolio and "originates" the optionality the trader needs.

Webinar available at https://bit.ly/30OlGEv

A Panel Discussion on the Move to a Transactive Energy Market: Engaging Prosumers While Optimizing the Electricity System with Location- and Time-Specific Price Signals

From 40th PLMA Conference

Dave MacRae
Opus One



Alex Rojas
Ameren

Paul Tyno
Buffalo Niagra
Medical Campus

Moderator Richard Barone
Hawaiian Electric Company

Richard Barone: Transactive energy is an exciting forward-looking endeavor. I think that it's directly related to everything that we do as professionals in demand response, but it's nothing if not nebulous. By that I mean it can mean a lot of different things to a lot of people. Today's discussion is aimed at looking at one particular flavor, one particular technology of transactive energy as put forth by Opus One Solutions and a few different projects. Dave MacRae will introduce those projects. As we get through the discussions that follow, we will hear from one of the utilities that Dave's working with as well as a customer perspective.

Paul Tyno will discuss the customer perspective. When we go through this presentation, my hope is that I will lead us through a discussion more broadly extrapolating from the current projects into general thoughts about transactive energy, what it means, where it can go, and then we'll engage all of you in the last few minutes of this to ask all of us questions about the subject.

To my right is Dave MacRae, and Dave leads business development and strategy for Opus One Solutions on the East Coast. He brings about 15 years of experience from Con Edison, where among many things he led efforts around distributed energy resource integration, grid modernization, digitization, energy efficiency, and demand response. He has got a wealth of experience that he brings to the table.

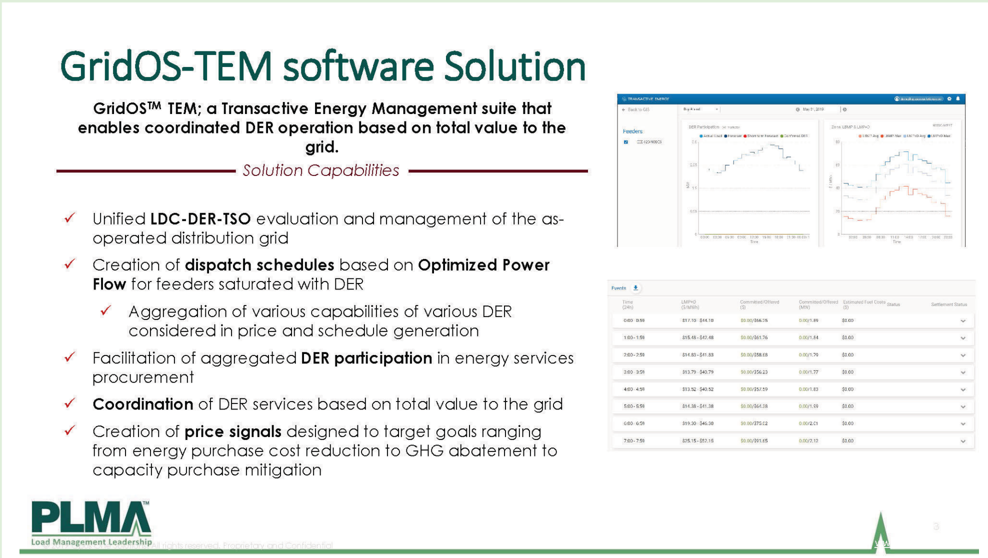
Alex Rojas is from Ameren Services, and has another impressive background, about 20 years of entrepreneurial engineering innovation in companies like GE, ABB, and Siemens shepherding technologies into utilities. Now at Ameren, as Director of Distributed Technologies, Alex is really part of an innovation and corporate strategy group, helping to find and develop forward looking strategies and sustainable business models for technologies and solutions there.

You all know Paul Tyno who you saw just a few minutes ago as a previous chair here of PLMA for three terms. Paul wears a lot of hats and I think it's too many to name, but I will say this, he is a recognized national subject matter expert in demand response for many years. But today he is representing the Buffalo Niagara Medical Campus, and right now he is the strategic advisor for their energy initiative. That covers a full gamut of things anywhere from distributed generation to energy efficiency, demand response, grid modernization, so forth. So, we've got a heavy load there and it's our hope that through the discussion of the projects that each of these gentlemen are involved with will start to elicit an interesting and compelling conversation about transactive energy and where it might be heading. With that said I'll switch it over to Dave.

Dave MacRae: My name is David MacRae. I'm with Opus One Solutions and have been there for about three years. As Rich mentioned, I came over from Con Edison and what we were doing in New York at the time, everyone's heard of Reforming the Energy Vision (REV) in New York? We are talking about how we're going to integrate and value DERs. What's the path forward, from an integrated distribution planning perspective through monitoring and control, and ultimately to distribution level energy markets.

If you haven't heard of Opus One, we are a Toronto-based company, and we do have some of our customers here with us today. We're a software solutions company, with a model-based analytics platform. We work with distribution utilities to unlock the value of DERS. It's more about granular, time/location-sensitive valuation methodologies. Once you can see where DERS are, you know what they're capable of doing, you can start to value them. And that's really what we're here to talk about today is that valuation.

Transactive energy marketplace is the solution that we have developed. We're working with Alex running market simulations with Ameren; and we've been working with Paul and National Grid up in Buffalo, New York for the last three years or so. That project will be wrapping up shortly. But again, the idea is that with a model-based system is that once you can start to see where those assets are, you can start figuring out the granular time series location-based value system is. One



SLIDE 14 View Slide at: https://bit.ly/2TQYgwM

of the things that's big in New York is the market should be technology agnostic.

Michael Brown was talking a little bit earlier on about 20 years ago where we were with the ISO and different markets and assets and going out in the field and figuring out what they can do. Where we are now 20 years later is that we can actually model that. We can figure out every single node, every single asset, sub-hourly, hourly, day ahead markets, and we can start to see what those assets are capable of doing. The idea of the transactive energy marketplace is to come up with a valuation to put a price signal out that will incentivize operation to meet the system's needs whether it's thermal limites or voltage constraints. We've talked about non-wires alternatives, perhaps you can operationalize assets to meet your system needs.

We mentioned briefly the project with National Grid and Buffalo Niagara Medical Campus. We met September of 2016 or so to kick the project off up in Buffalo. The idea there is to test out what a market looks like. So, if you're familiar with REV demonstration projects, the idea is to test if there is sufficient value in the local distribution system for assets to participate in a market? If there is sufficient value, which was proved out in the first phase in 2016, how do you operationalize that price signal? So, taking a planning construct, operational timeframes, and putting those price signals out in the marketplace for customers to respond to.

The focus there was customer engagement. We'll talk a little bit today about market animation and whether or not the signals put out there and the customers if they're ready, willing, and able to, can they participate in the markets what those values actually mean. The project that we're working on that Alex will speak to in a little bit, today at Ameren is more of a market simulation. Alex has done a lot of work to develop and build a microgrid. You can see some of the assets that he's been working with at their innovation center; they're looking at different renewable sources, wind, solar, storage, natural gas generators, backup generation. The idea is to develop an understanding of what that market will look like going forward.

When you have a lot of flexible loads, intermittent renewable resources, are there price signals that make sense? What is the construct while respecting the constraints on the system, when does it make sense for a system for DER to operate and not create a problem on the system? The idea there is to simulate the different types of loads there are in a marketplace and see how that can work.

Barone: I wanted to take one step back for everybody in the panel. You each have different projects you've been engaged with. Maybe a two-part question for you to consider. Firstly, in the context of your project, how do you define transactive energy and how does it relate to the concept as thrown around in New York, of REV, of market animation? Then on the heels of that response, think more broadly, is this the end all, be all? Is this what transactive energy is? Or can you imagine that there might be other permutations that go beyond what you're currently doing?

Alex Rojas: What motivates me is what I see is a likely requirement from Ameren customers for solutions in their energy from other places than traditional generation. That brings us to distributed generation. When you talk distributed, then you need to start thinking of how to better manage assets. I feel that there is a need to provide price for energy given location and time more now than ever that things are decentralizing. I see this just as a beginning exercise to start thinking of methods, credible ways to do that.

Working with Opus One, we call this a DLMP. So, LMP at the distribution level. We have been discussing different formulas and approaches around that. There are no right answers for now, but certainly exercise in my organization to think about that and to be ready when you know, customers really demand this in the near future.

Barone: If I can just interject for the benefit of the audience, DLMP is distribution locational marginal pricing. In your example, as you've just described it from where the utility is, "Hey, we've got costs associated with different aspects of our distribution network. Can we generate the right economic or market signals to deliver the services needed at that location at our cost or better?" Now that we have heard a utility perspective on transactive energy, let's transition over to the customer perspective. Paul, certainly with respect to your current project and maybe more broadly, what's the customer's view on transactive energy?

Paul Tyno: We're interested in a platform that allows commercial, industrial customers to optimize the flexibility of their energy and demand consumption. Respecting their priorities with respect to reliability, cost, and sustainability, but actively coordinating our assets and that flexibility in a market that provides compensation for us, then providing system benefits. I get, not nervous, but I think moving forward in a little bit broader thinking, I get a little concerned by limitations based on physical location.

From the standpoint that if we look too tightly at a focused geography, I think we're undervaluing the broader impact of DERS and the aggregation of those DERS. If we think about potentially stacking those clusters together, serving distribution assets and across the entire service territory, I think then we can start to assess that value against the broader system. I think we'll find a little bit more deployment of those kinds of assets in an active fashion and not just behind the meter.

Barone: Dave, do you see it the same way? While it's imperative to learn through targeted demonstrations, the real value starts to get unlocked as you start to look at a broader scale. Is that where you're going with that, Paul? I wonder if that's true from the Opus' perspective in terms of the law of big numbers and the power of the portfolio effect that you really start to see scalability–value distribution–as you get into bigger deployments. Is that some of your operating premises at Opus One?

MacRae: Absolutely. During the project with National Grid last summer, we scaled the platform specifically for that reason. To identify new customers, new technologies, and a different geographic area. An area that maybe has more system needs or maybe constrained. So the idea being that once the market, in this case, the platform, the more models you see, the more DERS, the capabilities of the customers and the different participation models and the value streams, that's when you can start to offer a more holistic solution to the market. I think early on a lot of demonstration projects are targeted to a certain test case or use case to prove out a specific methodology or evaluation. But it can't be all encompassing.

Alex, you see it over in Illinois where if you look at 3% market penetration of DERS, of peak load, that's when you really need to start looking at that pricing methodology and engaging customers. As you get more customers that are able to participate, you're going to be in a much more dynamic marketplace, which is going to start to unlock the value.

Barone: You've talked in different ways and your software does this, I think, by virtue of its foundational or fundamental technology, but valuation is a very important part of this. And what I'm curious about is, and Alex, you talked a little bit about locational value, which I'm going to presume, and you can correct me if I'm wrong, but it's essentially a cost-based approach. What other ways do we have in each of your experiences with assessing the valuation? I think in the long run, maybe if you have big deployments, the market can start to establish the valuation, if you will. But absent of that, what's your starting point? Dave, you've seen a number of different projects. How do you start? What's your ground zero for setting the valuation and moving forward from there?

MacRae: We started out in New York, if everyone's familiar with policy, which can be very exciting for a Tuesday morning, it was LMP plus D. So, it was locational based marginal price from the wholesale market plus that discreet value to the distribution system. What we worked on there, very similar to discussions we're having with Alex and some of our other customers, is that what does that evaluation look like? Part of it is policy, what are you allowed to do? Then do you have the right information to actually perform a calculation that's repeatable and provides some value. So that was taken from the planning construct of understanding where the value or what is the value of a distributed resource based on capabilities and where it is physcially located.

Then what we see in other areas is, as Alex mentioned, is the DLMP. So, it's more of like a bottom up calculation. Whereas LMP plus D, in its early stages, was what's the discreet value add for that asset based on the circuit that it is connected to? Where in this system is it? Is there a specific value that you can add to your LBMP? DLMP is more of a bottom up calculation. Trying to figure out more granularly where the asset is based on where it's located and a time series analysis. What it's capable of doing to match that up to system needs. There are different marginal cost of service values, and today there are tariffs based on the value of distributed energy resources (VDER), that is how we've moved forward in New York. So, there's going to be a lot of flavors of it and it really depends on more policy and customer engagement. Then again, how well can you map the system, how well do you monitor and control, are they able to respond in the time necessary for say ancillary services.

Barone: Paul, from the customer perspective, how does that valuation create your response preferences? How do you align or evaluate that valuation in terms of your willingness to get involved or participate in the long run?

Tyno: I think there's two sides to that conversation. There's, how do we respond to a monetization opportunity. The other side of that is how do we invest in order to position for that monetization opportunity? A lot of what we've done on the campus with respect to an active CHP project we have, I think we've missed a tremendous opportunity. So that unit will ultimately be right-sized, and at some point in time, as opportunities present themselves, that system has limited capabilities. So, I think the overall challenge here really, is to how do we look forward and not historically and traditionally at those economics because we're going to miss these sorts of opportunities. And if I can, just one other example with respect to how we string these clusters together. We have infrastructure in Western New York that Thomas Edison touched. So that's cool and scary at the same time. As the med campus went from six million square feet to 10 million square feet in less than eight years, our distribution utility, National Grid, was able to lay infrastructure in as an economic development initiative, so it was proactive, not reactive to demand entering the equation.

So that has put us in our little 120 acres in downtown Buffalo very comfortable. But I have this surrounding area that is now growing and in typical rust belt cities, that's where a lot of your oldest and most fragile infrastructure resides. So, how do we leverage the assets and the equipment and the flexibility on the campus to impact positively the infrastructure struggles that we're going to see now in surrounding neighborhoods?

Barone: Does that imply then that some of your investments – even absent of a future potential of this value based market – are really also a hedge against the threat to resiliency?

Tyno: I think you have to have that conversation, right, there's the stick and the carrot conversation. So, we have a lithium ion battery installation that should be deployed by the end of the year that a lot of the size and scope of that battery was built towards our future monetization opportunities at the distribution level. But that's a modular system so we, in turn, also have some flexibility there as well. But certainly, we're looking at those as economic development decisions as well as resiliency and reliability decisions ultimately trying to drive savings and revenue.

Barone: I'd like to engage you a little bit more in that you're a technologist by trade. A two-part question for you wearing your utility hat. What are the technologies that you're employing - IT and OT technologies - as part of transactive energy endeavors? Obviously, Opus One is a big part of the IT stack, but what are the technologies generally that you're deploying as part of your project, and where do you see, or have you already seen, the risks or the threats to successful project and scale if you were to think forward?

Rojas: Going back to 2015, we started deploying OT Technology. That is the DERS are controlled and monitored by primary and secondary controllers. So, we started some number of years ago to do OT. Now, we are looking at putting a layer of distributed ledger, the accounting on top of it. One of the biggest challenges that the industry, not only Ameren will face, Ameren is facing right now, is how to integrate both that layer of OT with that layer of accounting. Why? Because the constraints are held by that OT layer. That is thermal constraints and voltage constraints that have to be observed by the accounting of the energy trading as actors bid or as they react to prices. So it is that integration that's going to challenge us. Some of you may follow transactive energy deployments around the world, and I see that being a major challenge for most.

Barone: In layman's terms, the fundamental challenge resides in the nexus of the physics of your system and the economics of the transactional framework. Those two things have to work in harmony but they're two very, very different worlds. That's probably where folks like Opus One can help. How do you harmonize the physics of the system with the economics of the transactive framework?

MacRae: Our approach is model based, so we work with our customers--distribution utilities. Our platform is common information model (CIM) native working with the as operated network system, and that's the only way that we're able to figure out based on that and any sort of real time telemetry or say hourly, sub-hourly to understand what's going on in the system. So, you can tell when there's a thermal limit, when there's a voltage limit, if there's going to be a constraint later in the day.

Using a short-term forecast, looking at what that is coming in, possibly if they're using AMI. So using the data that's available for the utility and helping them to operationalize that data in one platform to figure out what the economics are and putting that price out in the marketplace that actually respects those constraints or potential constraints or issues and properly rewarding assets, or increasing the value based on the services they can provide when they're most needed.

Barone: Paul, on your side, I guess you're going to be responding to those signals. Do you establish the preferences and parameters around response relative to different economic trigger points?

Tyno: Every institution is going to work within their own comfort level, within their own risk management structure, and the economic opportunity itself. A lot of that will be determined by how the assets that they are deploying them to respond. I think we don't worry about technical solutions; we don't feel like technical solutions are the obstacle. I mean our focus really is on helping Opus One in the DSP project, really the development and testing of new business models, because we've got to define these financial, societal, and intangible benefits in both directions, utility to customer and vice versa for really this to grab.

Barone: I'm going to take one step back for everybody in this room. Probably some people are wondering 'Why am I at a demand response conference and the first panel is on transactive energy?' I have a question I want to pose for each of you. Since you've had a longstanding experience in both DR and utility industry respectively, do you consider transactive energy to be an evolution or a revolution to demand response? Is transactive energy divergent from or a necessary growth out of what we've done for decades in demand response? I'll start with you.

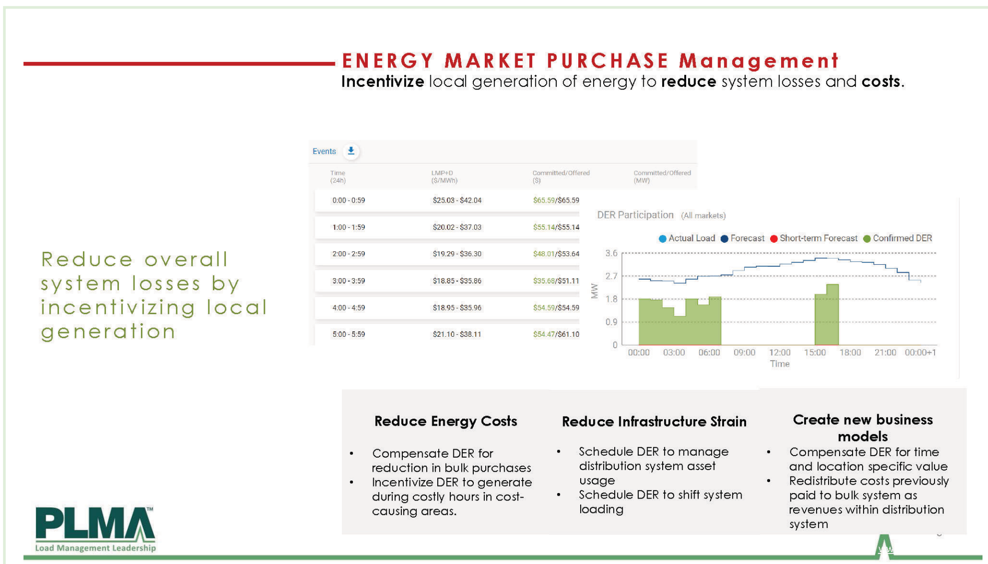
MacRae: I think it's a natural evolution. A lot of what we talked about when we were designing demand response programs at the utility and working with the regulators, it's all a tariff approach. It's usually based on a socialized marginal cost of service. You figure out what the value is. If you have a high value area, you can say, "Okay, well we'll pay an extra for this megawatt in this specific area based on the services this can provide." So historically it was more of a coordination between the balancing authority or utility and their customers. But that valuation, it's not necessarily the best, maybe you're paying too much for the services provided by that asset. It wasn't quite surgical or specific enough. So, a lot of times the state will call everything 350 to 400 megawatts across the entire state. Are they really providing the value?

So, I think transactive energy is like the next natural evolution in that once you have better mapping, better monitoring, better visibility, more monitoring and control of the assets, you can start to figure out what the right value is for that asset. Now you can pay only for the assets and the services that you need when you need it most as opposed to maybe setting back a thermostat or a hot water heater that while it adds a lot of value, is it that $5 reward per event? Is it that $50 a year? Is it just the one incentive that that is a very cost-effective way to engage customers and provide a service as we get more dynamic with the capabilities of our assets? We need to figure out much more granularly what that value is.

Barone: I tend to agree. Alex, what's your perspective?

Rojas: I think it is a revolution but the reason I'm starting earlier at Ameren is because I'm trying to make an evolution for Ameren. It's a large start organization and I want to make sure that a lot of these customer requirement, customer expectation, changes don't catch us by surprise. So really, evolution internal for Ameren, I presented this, the price signal aspect of this as an evolution from time of use. I'm trying to kind of preach a little bit of that internal to Ameren. It's been challenging actually. I agree with technology not being an issue.

For me, it's convincing fellow executives at Ameren to support me and trying to convince them that this is a likely need for our customers coming in the future and that we should start early. Let me highlight what fundamentally drives me. I see this as an exercise to optimize asset deployment and asset management. So, I believe that a market, in this case being our local market, will determine where that generation asset should be placed and what size it should be and when it should operate. So that's kind of my philosophical view around that.



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Barone: Paul, I'm going to twist the question a tiny bit because you're on the customer side. I think we can certainly be guilty as an industry of thinking of all of the technical solutions and all the ways that we're going to get something approved by our regulators wearing a utility hat. But the customer is really the engine for making a transactive system work. I'm curious from the customer perspective–two questions really. Do you see this as an evolution or a revolution for demand response? Then secondly, being a customer and engaged in this, if you were going to give advice to both utilities and software providers alike, what is going to be required to engage customers in this?

Tyno: Thanks for the softball there, Rich. I think, you know, we view it as an evolution, and I think that sometimes we get caught getting down on the commercial industrial side to the type of asset. I agree with David that certain assets have certain characteristics that provides certain value back to the system in their ability then to respond. But at the same time, I look at the building as a whole, as an asset. So, a lot of our initiatives are tied to not supply or consumption reduction, they are applied to demand management. So, DR is a strategy within the umbrella of demand management then to drive savings within the building.

I think the broader system benefit is again, when you start to cluster the capabilities of those buildings. So, I think one of the challenges, and I've been fortunate enough to be in the room, is that the conversations really can't continue only between or primarily between the regulator and the utility. The customer has to be in the discussion and engaging them at that standpoint, I think, helps you build and drive something that's far more sustainable.

If I can, I'll just pile on with a point B to that is I think it's imperative that we work at the pace of business. We do not work at the pace of business right now. So, absent the reasonable pace and path, right, these customers were going to continue to adopt behind the meter measures, and every time they adopt the behind the meter measure, we just kind of increase that level of grid independence. That brings on a whole different set of challenges.

Barone: I'm going to reciprocate my appreciation for helping with a nice transition into my last big topic, which is the utility business model. I think transactive energy could be a friend or a foe to the utility business model, but I think either way it lends itself to business model transformation for the utilities. I'd like to ask each of you, and maybe we'll start with Paul and work back this way. To what extent you think that's true? What are the implications for changes to the business model of the utility from where you sit and along those lines, think about some of the regulatory impacts that would need to occur to facilitate and foster a sustainable business model transformation?

Tyno: Obviously a challenge. I mean, we firmly believe that we will get to a better solution with our utility involved. We talked grid independence, but that's really not the objective for anybody. I think it has to be an expanded conversation. Really, the core challenge is how do we utilize a customer-to-grid asset, fostering participation, but with a level of control that allows the whole system to work. So, to your point, success really is tied to regulation and market animation, but we have to unlock those economics. We have to create a level of motivation, both for the utility, and for the customer to proceed forward, to think differently, and to innovate.

Barone: Alex, how does the utility realize value in this situation and what implications do you think it may have for the kind of the old school utility business model?

Rojas: Sure. let me start by saying that in over 20 years of deploying and developing technology for utilities, I've learned not to fight the laws of physics and the laws of market. So, this is what I mean. It is due to the laws of physics that complete independence of a customer's premise from the grid is unlikely due to balancing. There are too many technical details that we're not going to go into, but DERs really need an infinite bus to hook up to for stability, lots of physics. Lots of market customers, millennials, and others will start expecting some different from the utility. That's something I'm not going to fight.

The good news is that large utilities like Ameren are important stakeholders in state capitals. I believe that if there's a friendly relationship with regulators and other stakeholders, I can see formulas in which everybody wins for reasons I'm trying to explain. And you know, I can see a way in which the grid remains at the center of value creation while letting customers obtain their energy from the sources they like and when they like and at what price. So, yeah.

Barone: Dave, you're in a very unique position because you've got 15 years utility experience and now three or so years at Opus One. So, you've seen both sides - the solution provider and utility. Alex referenced there are formulas where you can create value, and I'd actually argue that's a triangle, right? There are intermediaries that have to make a business out of this, utility has to stay whole, and customers have to have value in this as well. What aspects have you seen to date where you're starting to see pieces of that formula come into focus? What is working, so far, in this evolving frontier?

MacRae: I'll stick with New York. I mean early on if you go back again four or five years ago, 2014, 2015, at the start of the REV in New York, one of the interesting projects I've worked on in Con Edison was the Brooklyn Queens Demand Management Project. And in one of the regulatory constructs, there was an earning adjustment mechanism. So, there was an opportunity for the utility to earn their ROI based on successful investment. I think the early markets are really going to be driven by that. So, to the extent that the utility can incentivize placement and operation of DER, whether it's based on avoided energy cost, avoided capacity charges, OPEX, T&D, infrastructure, capital investments, you should be able to earn something on that.

So the idea with a flat/declining load growth across much of the country and many areas of the world as well with increased efficiency, less usage, I mean you were seeing that pretty much everywhere is you need to change that paradigm from a policy perspective and allow utilities and their investors to be made whole in order to keep the lights on with an increased level of reliability and resiliency. That's one model that can work.

Barone: So to put it in contemporary, hot buzz terms from the regulatory side, what I think you're saying is that using performance-based regulation or performance-based rate making as a means of getting utilities to transition away from a capital bias to facilitate this type of an arena is one key lever in keeping the utilities whole and advancing this. Did I read too much into that or is that what you were saying?

MacRae: That's where it's got to start. If you're going to transition, you're not going to go to a fully-fledged market. You don't have the monitoring and controls in place today. You don't have the communication standards, too much latency. There are data issues. Customers, as Paul mentioned earlier, if they're trying to right-size equipment based on their needs today, if there's not a market evaluation that they can rely on, they're not going to make that investment. We've seen that with CHPs and engines for decades. All of our load is 10 megawatts. So, we're going to put 10 megawatts of generation and we've got plenty of space.

So, I think, setting those valuations and that they're going to change over time with technology, but at least setting something to start out that a customer can rely on to make that investment they're going to be more willing to participate in the market. Once that market gets up and running the methods can change, but you still need that key valuation and need both parties to be made whole.

Barone: I agree 100% and we're living a lot of that right now in Hawaii as we're facing a PBR docket and tackling all of these issues from PIMs to EAMs and so forth. Now, we're going to try to open it up to questions in just a minute, but I'm going to ask each of you one last pair of questions: What is the one thing that makes you most excited about transactive energy as you look forward, and so far, what is the biggest surprise, pitfall, or challenge that you've encountered so far that you think really has to be ironed out for this thing to work? I'll start. We'll start with Dave and we'll conclude with Paul.

MacRae: The most exciting part was when the markets actually went live in March of 2018--so a while ago, 18 months ago. We talked a lot about it from a policy perspective. We were writing DSIPs in 2016. That's the five year road map. How are we ever going to get to the markets? National Grid as our partner with BNMC took that step to say, "Hey, this is what the market may look like and let's go try it." Let's work with some customers like Paul and now Ameren's doing the same thing with their own flavor of it. So that was exciting to see some actual movement. It was real, not just a study or an approach, but actual live working software.

I think the biggest challenge is going to be, it's tied between technology and policy. So, policy can only enact things that are out there that are going to be installed today. So, it's kind of like a chicken and the egg as far as that component. We talked a lot about IEEE 2030.5 or OpenADR, what's the communication standard going to be? We had a good discussion last week on 5G and how that's going to transform the markets. Until manufacturers have that, and we can integrate with it, from an integration perspective, it's relatively simple.

But you need to have the technology out there. It needs to be trusted, it needs to be better, it needs to be getting installed so they can participate in the markets. So, I think that's the challenge and it's twofold. It's really on the technology getting out, but then having the policy that enables you to make the investments in that technology.

Rojas: Most exciting is that I see likely applications for most of what we've spoken about and one would be, for example, EV fast chargers. They're coming strong, or they're affecting most of our areas. And there is a likely need for customers in a new feature to expect energy prices be displayed in a map. Just as today, gas stations do have pricing if you use the right application. I see that one scenario. Very likely, especially at level three charging, which is very intense, 150 kilowatts intensity are just equivalent to about 15 homes that our model three Tesla charges at once. So, it's going to be a stressing the system, which will require stakeholders like Ameren to start pricing and start implementing or representing what is the agent that that infrastructure is having on our assets. So that's exciting then because this will be you know, very useful what we're doing.

Challenges, I'd say mostly around relationships and organizational behavior. Challenges are relationships with our regulators, relationships within large organizations like Ameren where folks need to be aligned and have to have a purpose and a goal to achieve these what I'm describing.

Tyno: So I think what's most exciting is the innovation and the connection of energy to economic development and moving the economy. Energy for us is going to be one of the bullet points on the double-sided glossy that says bring your business to Buffalo, bring your research center to Buffalo, expand here and energy will be one of those bullet points alongside cost of living, access to human resources, the things of that nature. So, to me that's very exciting because that'll drive the market.

I think the biggest challenge is fear of failure, and that's a really short sentence that really means a lot. But there are times that we get funneled into a demonstration project where we have presupposed outcomes. So, we really don't push the ball forward because there's lack of the right environment to take that leap of faith and to really do something, and if it fails and there's learnings from that as well. But it opens up the possibility that it may succeed.

Barone: Great insights. We have about five minutes left and I wanted to open up to all of you to ask our panelists some questions

Phillip: Rich Phillip from Duke Energy. Paul, if I remember right, from conversations often during the New York REV process, you–representing the Buffalo Medical Campus–were the only customer at the table. Is that true?

Tyno: That's true.

Phillip: And so while I'm at 100% agreement with you relative to the importance of the customer voice and how we drive this forward, you know, frankly, they were very lucky to have a representative like you that has seen as much as you have in this business. You are getting outside your depth initially on a lot of these more particular technical issues, right? And so how can we get customers more involved going forward into a world that will seem almost mystical to some?

Tyno: I think it's discovering champions and fortifying that relationship between the utility and key champion customers, right? We literally have an MOU with National Grid. It's a memorandum of understanding of how we're going to develop and work in partnership. It doesn't describe specific projects, doesn't provide us any distinct benefits with anything with respect to pricing or anything of that nature. It just says that we're going to get around the table on a regular basis and we're going to discuss issues in both directions and we're going to try to create innovative solutions to those questions. So, I think that's really, really the key because there are people out there, the depth of experience is tremendous, and it's just that willingness to bring another voice to the table.

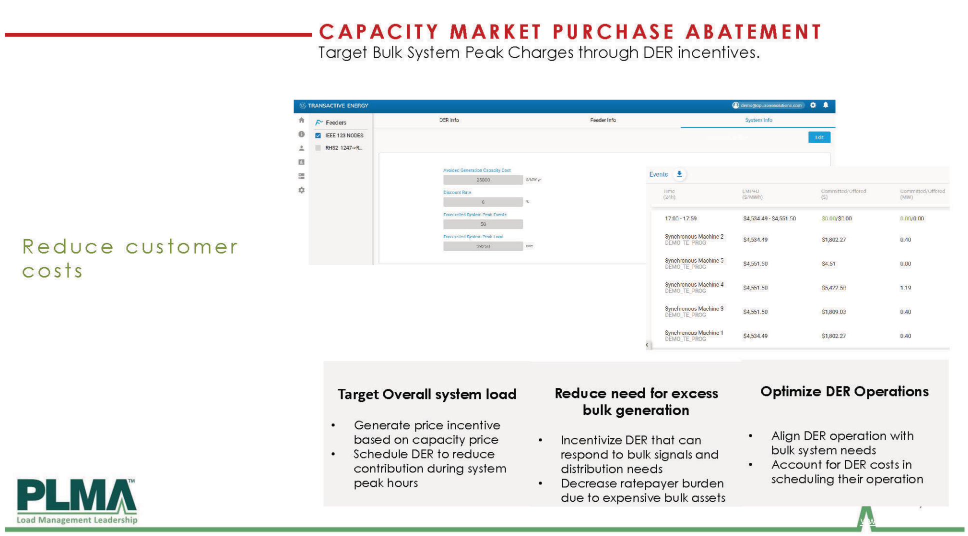
Dave Erickson: Dave Erickson, New Hampshire Electric Cooperative. We are in the process of engaging in developing a transactive energy pilot and expect to have something rolled out probably 2022, and we're taking a lot of care in how we're designing this thing, and a lot of questions have come up. one of the main questions right now, and this is kind of down in the weeds, but how important is it to support peer-to-peer transactions? We believe that it's one of the primary goals to properly value energy, as you've stated, in potentially other grid services on a locational basis. But as you push out a price as you know, say, we push out a price as the utility, how important is it to have other entities be able to respond to that price and to be able to actually do peer-to-peer kind of transactions? Then the second part of that question is to what extent do you think it's necessary to invest proactively in infrastructure, communications, infrastructure, the platform, all the supporting infrastructure to support a transactive market in advance of high penetrations of DERs?

Rojas: Peer-to-peer is not a requirement necessarily. I see this, the way I'm thinking about distribution-level energy trading is similar to what the industry has done in bulk energy trading for years where you bid, you interact with a market, not necessarily with the peer. Peer-to-peer may be what a local transactive energy market may like, whatever, a cluster of prosumers and the consumers. But I'm tending more to see this as a little bit of extrapolation of the energy bulk market in the way how that is handled. Very complicated though at distribution level because you have thousands of circuits versus a few hundred lines on transmission. Yeah.

Barone: I'll just add something as I take off my moderator hat for a second. As a utility person, I think peer-to-peer at the mass market or residential level is a nice concept, but I'm not convinced that it's going to be the most efficient, personally. I think a lot like the wholesale market, you may need to rely on intermediaries or aggregators to roll up those transactions instead of dealing with onesies, twosies. That's just my current thinking on it. And there was a second question in there as well. What was the second question?

Erickson: It was related to proactive spending on creation of the infrastructure. There needs to be a lot of infrastructure to support this–communications, platform, et cetera. In the absence of an already existing population of DERs that could potentially participate, how do you manage that development of your system to support this? Do you have any perspective?

MacRae: Maybe we can chat later. We've done a lot of work with grid modernization, with munis and



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coops and the foundational investments, you have to look at what the values are and what your needs are. So, what are your challenges? What are your needs? That's going to determine what your investment is. So, if you're looking at just AMI, there are a lot of benefits. There's a lot of business plans out there that we can, you know, between us and our channel partners help you figure that out. So, there is a roadmap that can be defined based on your current investments and where you want to be and how quickly.

Barone: I'll echo that, and we should talk offline, but you wouldn't, I think make investments specific for transactive energy, but rather instead, part of a larger forward looking strategy. I think we're pretty much out of time, but if we can have maybe one more question, we have a few people queued up and then we'll wrap it up.

Joseph Childs: Joseph Childs, Eaton. One of the big barriers moving forward is getting open standard answers to the value, the locational value, of improving the distribution system, operation, and reducing load tap changer operations, reducing the decay of the power line public, and a set of standards. When I talked to our power system engineers, they say, "Well, it depends." So how do you think that we can move this to numbers that we can start passing around to engineering groups that that we can see published, blessed by people that say, you know, "Here's how you can value this stuff in an individual distribution system."

Rojas: I would point to the EV charging infrastructure. The journey in North America that that deployment has taken is a good way to go visit, understand it, and not repeat it. Because right now the charging networks are facing challenges around proprietary technologies versus open standards. So that's the best answer I have for you. Yes, I agree technology is a challenge, but let's not repeat what has happened in deploying EV chargers.

Tyno: I think you're going to have to have a blend of prescriptive valuation and customization because you're going to have some geographical impacts to that. In New York, for instance, if you are generating renewable power upstate, but it needs to get downstate and the transmission piece to that makes that somewhat of a unique conversation to maybe any of our neighboring states. So there's always going to be kind of that custom flavor in there as well.

Joe Gilbert: I'm Joel Gilbert, Apogee Interactive. First of all, I commend you for what you're trying to do because, in many ways, it's the next generation of what we tried to do 20 years ago so good for you. My suggestion is the people here who know what you're talking about, know what you're talking about. But with 50% of the audience being new, I am not convinced that everybody understands the distributed level of valuation here and the dynamic, the temporal... This is a very complex subject.

Our biggest challenge 20 years ago was facing the regulator and trying to put this into the market, facing the generator who was not happy about us depressing the peak price, facing the people who are engineers in the business, who liked to build things because that's what engineers do. And unless we can make this easy to understand and easy to discuss as optionality, I'm not convinced we're going to get very far because we're arguing about how many angels will fit on the head of a pin, and then not everybody believes in angels.

Barone: Thank you, and duly noted. This came up a bit earlier when we discussed the importance of stakeholder engagement. And educating customers and simplifying this, and we even alluded to intermediaries as playing a key role in that, are necessary for any degree of success in transactive energy. I want to thank you for ending on that. It's a very key point and a good place to leave this conversation and we're happy to continue it out in the hall.

Presentation slides available at https://bit.ly/3ay6NdX

Get Smart: Con Edison and Eversource Manages Peak Load and Meets Customer Needs Through Pilots

From 40th PLMA Conference


Annie Ramkissoon
Con Edison


Zach Sussman
Con Edison


Candice Tsay
Con Edison


Leigh Winterbottom
ICF


Michael Goldman
Eversoure

Leigh Winterbottom: Hello, I am Leigh Winterbottom, your moderator for today's session. I am also a senior marketing account manager at ICF where I serve as the project manager for ICF's implementation of Con Edison's innovative pricing pilot, otherwise known as the Smart Energy Plan. Let's get started.

Over the past two years, Con Edison and Eversource have undertaken cutting-edge pilots and demonstration projects that feature customer-centric rate and technology initiatives for peak load management. Our panelists today are going to cover key topics such as customer engagement around demand rates, gas DR, varied technologies like solar and storage and traditional DR. We'll touch on pilot design, implementation, approaches to partnerships and trade allies, and balancing program scale and customization for customers technology solutions.

But, really, our focus is going to be on lessons learned and recommendations, especially around meeting specific customer needs and increasing customer participation, engagement, and retention. Each panelist will introduce their pilot or project, then we'll have a discussion amongst the panelists. Then we'll open it up to your audience for questions.

First up, to introduce Con Edison's innovative pricing pilot is Annie Ramkissoon. So, a few words about Annie: she is a Project Manager on Con Edison's innovative pricing pilot team. She leverages customer intelligence and design thinking to inform innovation, strategy, and execution to offer customers more ways to manage their energy.

Annie Ramkissoon: Con Edison's pricing pilot, also known as the Smart Energy Plan, is the company's mass market rate design pilot. We designed a new pilot because today's market rates don't really give customers the appropriate price signals. And so, it's critical that we start shifting delivery rate design so that it's more cost-based and can give customers the right signals to help drive cost-efficient behavior, such as encouraging them to spread out their peak usage as well shift to off-peak periods.

Our pilot really tests three flavors of rates. There's a portfolio of seven rates, broken into three categories. We have demand-based, subscription-level, as well as a hybrid rate, which is based on both volumetric and demand rates. These rates vary across peak hours, as well subscription levels, so we can test the differences across each.

The pilot focuses on serving residential and small commercial customers in Staten Island, Westchester, and Brooklyn. We're using two customer recruitment strategies: opt-in and opt-out enrollment methods. We are targeting customers in these geographies with recruitment tactics and encouraging them to participate in the pilot for about two years or so.

Each pilot phase – or "waves," is broken up into three waves and lasts about two years each. You'll see that, in how our pilot was developed, it starts in a very successive way where, with each wave, we're adding additional geographies, as well as additional rates and recruitment strategies.

The objectives of these pilot are to help inform our future rate design so that we can shift to a more customer-centric approach. Also, another key objective is looking at how our pilot is going to be received by customers. In order to help us inform our rate design, we need to understand if customers accept these rates and at what enrollment rate, as well as how do these rates affect their bills and load impacts.

A key metric for our pilot is not only just enrollment rates, but we're also looking to see how it affects their bills and their loads and how we can help use energy smart behaviors to help customers manage that.

Some early results we've seen so far is we have had higher participation than we projected. Also, we are seeing high awareness and high satisfaction with the rate. So far, about 80% of our customers are aware of the new plan and about 95% of customers surveyed have reported high satisfaction. So, we are pleased with the early results.

As I previously mentioned, our pilot is divided into three waves. Our first wave was launched earlier this year in April 2019. We went out to market in Staten Island and Westchester to a small population of residential and small commercial customers. We started to bill customers in April, and they were recruited through the opt-out enrollment strategy. What that means is that we were going to default enroll them onto the rate, unless they opted out before billing began in April.

We enrolled close to about 14,000 customers this past April. Then we served our first bill in May. Since then, six billing cycles later, we have a less than 7% opt out rate since billing has begun, which is tremendous. We originally projected about 20% or so. So, we're seeing good retention there.

We've also launched our first survey. As I mentioned earlier, we are seeing really good response rates. As of the date of this presentation, we have our second survey in field, which is focusing on how customers are responding to the new plan now that they've been on the plan for a full summer.

Our second wave concluded in October 2019. We recruited customers across Staten Island and Westchester under both an opt-in and opt-out strategy. Customers that were recruited via opt-in were offered a rate, and they could voluntarily participate in that offered rate.

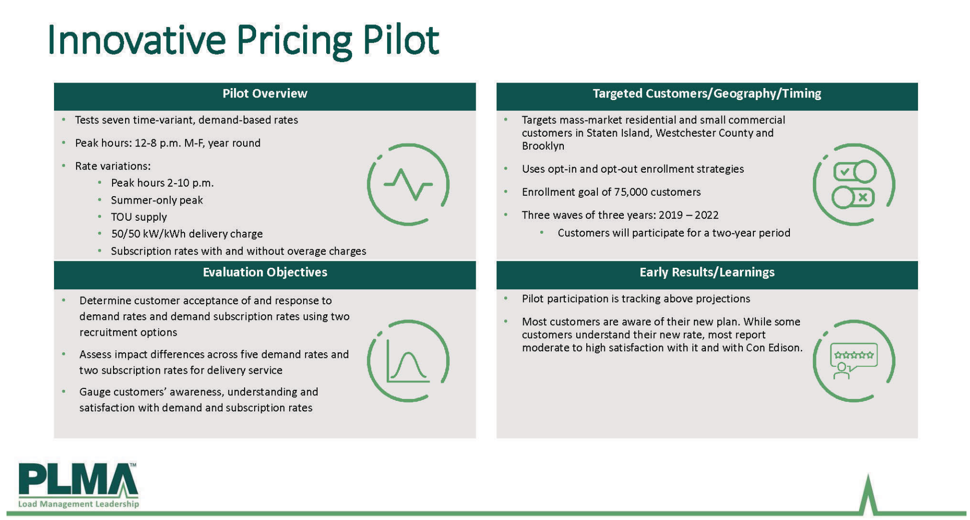
We enrolled about 16,000 customers this October, and we're getting prepared to send our first survey to welcome customers onto the plan, but also to help create those initial baselines around awareness and understanding of the plan. we're seeing so far is similar to what we saw on Wave 1. So, we're very excited to see what the results of the Wave 2 deployment will show.

We are in the middle of Wave 3 preparations. Wave 3 is being deployed in Brooklyn, which is going to be a different demographic for us, and more representative of the New York City service territory. We are very curious to see how these results will differ based on these demographics.

The Wave 3 deployment in Brooklyn will be begin with our first Test and Learn campaign, which is a small-scale test that we are doing to a small population of Brooklyn customers. This small-scale test will deliver varying communications to customers to help us understand how they respond to the plan, different channels, and various offers. We will then use those results to inform our larger, full-scale recruitment campaign, which is set to launch to a much larger Brooklyn target population in 2020.

We are enthused about the results we are seeing so far, and we want to see how this is going to expand as we expand into other territories. We are also excited to see how these approaches will change with other pilots we conduct.

While Con Edison is conducting this pilot as part of our mass market rate design, we also are testing a smaller pilot, which focuses on how we can help customers better manage their energy use with technology. That pilot is being led by Candice Tsay, who is my colleague. She's a Project Manager of the Smart Home Rate Pilot, which is, as I mentioned, aiming to provide customers with new ways to manage their energy use. Prior to joining Con Edison, she was working on energy and climate policy at the New York City Mayor's Office of Long-Term Planning and Sustainability.



SLIDE 17 View Slide at: https://bit.ly/30UI6ny

Candice Tsay: I will talk a little bit about the Smart Home Rate Project that Con Edison and Orange and Rockland Utilities is implementing. The Smart Home Rate Project is a pre-pilot that is designed for a particular type of customer. We are testing a rate that is provided to customers that are determined to be tech-savvy, that are DER users, and that are otherwise highly engaged residential customers. We will be providing participants with a home energy management technology that can automatically manage certain loads in the home in response to dynamic pricing signals.

The rates that we are testing will have hourly energy prices and demand-based delivery charges, as well as critical peak pricing event charges that the technology will optimize against. We will be exploring two different technologies. Therefore, we have structured the pilot to have two different research tracks. In Track 1, we are featuring a smart thermostat powered by Uplight's

Orchestrated Energy platform. In Track 2, we are featuring home battery systems from Sunverge, coupled to rooftop solar. ICF is our partner handling all customer acquisition and implementation.

The pilot's goals are to measure load impacts and to understand bill impacts, as well as gain statistically significant results that we can use to inform future rate design. We are also, overall, hoping to gauge customer acceptance of price responsive technologies in the home along with complex rates. By putting this new concept out there to customers who are likely going to be the early adopter types, we will hopefully be able to answer the question: is this what our customers will want in the future?

In Track 1, we are conducting a pilot with two different rate groups and a control group, with up to 750 customers in each group. In Track 2, we're set up to test one rate with up to 100 customers. One lesson we'd like to learn is gauging the customer perspective in rate design. We hope to be able to do this, along with meeting objectives around revenue recovery and state policy goals. For example, in the Smart Home Rate, we have demand charges that are based on 60-minute intervals knowing that they're diverse loads that make up the residential customers' load profile.

Another lesson we would like to see if we can learn would be if utilities can use small-scale pilots to test bold new ideas. In the Smart Home Rate, we're trying a brand new way of engaging with customers, and we don't know if we'll be successful. That's part of the reason why we're doing it. It allows us to stay ahead of the curve, as opposed to trying to react to changes in the market or with regulatory changes.

As of right now, we have just launched the recruitment campaign for Track 1. The first emails and direct mail were launched in early November 2019 with the headline, "Get the Thermostat that Never Sleeps." We hope to launch the recruitment for Track 2 in early 2020. The rates themselves will be active in/around April 2020 and run for two years after that.

Now it's my pleasure to introduce the next speaker, my colleague Zach Sussman. Zach is a Senior Specialist at Con Edison and is the Connected Devices Program Manager and a member of the Pilots in Emerging Technology Team and Energy Efficiency and Demand Management. Zach evaluates and runs pilots around the smart home and smart building technologies to find benefit for both customers and utility.

Zach Sussman: I'm going to be talking about our Smart Gas Water Heater Pilot. For background on this pilot, in March 2019, Con Edison announced that there would be a moratorium on any new gas connections in the northern part of Westchester County. We are a gas utility (also, electric), but we do not provide natural gas everywhere.

One reason for this moratorium is the fact that our utility has some supply constraints. We have a lot of gas customers. We have not been able to get the pipelines approved that will bring more gas here, and we had a very successful oil to gas conversion program. As we started to look at the issues of gas constraint, we created what we call non-wires solutions. Another term for this type of solution that is commonly used in our industry is "non-wires alternatives." That has morphed into a term we use called, "non-pipeline solutions."

As part of this portfolio, we asked the question: can we do something with gas water heaters? They comprise approximately a quarter of the gas load in a home and approximately half the gas usage. We were interested in exploring what solutions we could devise to address gas load and usage in a supply constrained environment.

We discovered a technology called Aquanta. It is a water heater controller, newer technology typically seen working with electric resistance water heaters. Aquanta makes a model that works with electric ignition gas water heaters. The technology will turn the pilot on or off to the burner in order to start modulating the temperature. The product plugs into most water heaters with a standard port developed by, I believe, Honeywell some years ago.

We are trying to measure three metrics with this pilot. The first is gas efficiency. The second is gas DR. The third is, simply, customer satisfaction. We recognize that with technology like thermostats, controllers, and any other type of connected technology, the technology will modify the home system. Therefore, we want to ensure that customers remain happy and satisfied under those circumstances. We don't want to make it too cold or too hot, and we want to maintain a safe environment for the customer.

At the moment, we don't have any results from the efficiency side or gas DR. We have yet to experience a winter season under this pilot. We're still working on approaches to measure the DR portion. It is easier for us to measure the gas savings, so we are focusing on measuring efficiency first. We'll still be running gas DR to measure customer satisfaction, but we won't necessarily have any savings numbers in that analysis to target.

We have set installation targets. Our goal would be to install 300 models in the customer base for the pilot. Currently, we are at about 175 units installed. I was very excited to see that we're at 93% customer satisfaction, which, compared to the other programs in an energy efficiency residential portfolio is very good and the highest so far. It is important to keep in mind that we are providing white-glove service by going into the customer's home and directly installing this water heater controller. Also, we have not yet adjusted the thermostat or the water heater thermostat.

The water heater controllers sit on top of the water heater. Therefore, the technology doesn't require the need to make any holes in the water heater, except to the shell of the mount. So, it's safe, and it could be a DIY solution, but we'd rather have a contractor do it right now. We're in the process of working with our evaluation team to figure out how we can measure this. At this point, I would like to introduce Michael Goldman.

Mike is the Director of Energy Efficiency at Eversource Energy. That's the largest gas and electric utility in New England, across three states. He's responsible for the strategic direction and regulatory strategy for their behind-the-meter peak load reduction and load management programs.

Michael Goldman: I'm here today to talk a little bit about some C&I demonstration projects we did for peak load management. Before Eversource even thought about what the types of strategies or solutions were that we wanted to test, we first started by trying to articulate what problems we were seeing in our region. Then, by defining the problem, we could figure out what the technology solutions should look like.

Our problem was, we were trying to reduce the ISO New England single hour. I think in other jurisdictions, it's called critical peak. But it's our ICAP hour. It's the hour that sets the capacity cost allocation across the region. By reducing our coincident load with that one hour, we would be able to reduce cost that would be allocated to our customers. Tangentially, that is also when you have the least efficient power plants running. It's not always, but usually when you have the highest. Therefore, we thought there would be a number of different benefits by trying to reduce that single peak hour.

As we thought about that problem, we decided to really dig into our customer class and our load shapes in terms of what was driving that overall ISO New England system peak. The slides that I am sharing in the presentation today shows the different rate classes of our legacy Boston Edison company.

This graphic shows that peak is really driven by the aggregation of all the different rate classes. As we explored this issue further, it became clear to us that peak was not being driven by a single rate class.

While it looks like it is residential, it is much higher. That's the R1 rate. If you actually aggregated all the different C&I rates, they're still disaggregated in this graph. If you aggregated all of those, it is still higher.

As we thought about how we were going to tackle this problem, it really occurred to us that if it is really the aggregation of all these different rate classes causing the peak, we need solution sets that would work for the different classes. We could not just target one rate class and could not propose a one-size-fits-all type of solution.

Where we landed, and what we wanted to test out, were different technologies with the aim of developing a portfolio of offerings for our customers. We landed on battery storage, two types of thermal storage, phase change material and ice storage, software and controls, and then more of a manual curtailment or traditional demand response, with the idea being that we then aggregate all of these on the back-end and try to dispatch them in a coordinated fashion.

The objective of the demonstration project was to go after that peak hour and then figure out what other ancillary benefits we could generate through that strategy. We developed a portfolio of flexible solutions that was absolutely critical, because we have different customer classes that have different needs that peak at different times.

We are also seeing the peak happen later in the day in New England, so we need solution sets that work for commercial industrial customers later in the day, maybe even after their business hours of operation or their business hours are over. We really wanted to make sure that we had these different solutions that will be applicable to all of those different customer classes.

Another key point is that it is important to strike the right balance between customization and scalability. You can't offer everything to every customer. That's just not feasible if you want to scale this up to have some material impact on the overall system. Therefore, the question became: how do you strike that balance between having enough customization with the ability to scale an effort like this that would allow it to expand significantly going forward?

We ran these demonstration projects in 2017, 2018, and through most of 2019. We have a couple individual battery sites that are going to still be running through 2020. We have some data that's come back from the projects. Everything has more or less worked how we had anticipated.

Of course, there are always hiccups. For example, we tried to site a large battery at a university, behind the meter, and initially the town said we couldn't site it there because the location was not sited for generation. They considered batteries generators. So, we had to explain to the city that it wasn't generation.

Then, when we actually did site it, the fire department required security barriers to stop cars from driving into it. However, the fire department then told us we placed the barriers too far from the battery and they would not be able to get their trucks close enough to it, in case of fire. We had to deal with those types of situations. Another example was they wanted what was essentially a drainage ditch much closer to the battery facility than where we wanted it. These are the types of learnings that came out of these demonstration projects that helped us better understand what issues we might face at scale.

Everything that Eversource does across our three-state service territory is on a three-year planning and budget cycle. Therefore, we were able to use the pilot results from '17, '18, '19 and include them in our next planning and budget cycle. I will talk about this further in our Q&A portion of this presentation, but you will see that these are now more or less in a programmatic offering. We were able to use the insights we gained from these demonstration projects to help inform what that programmatic rollout has looked like.

SLIDE 18 View Slide at: https://bit.ly/38wdjzU

We started in Massachusetts, and we have now integrated a lot of these types of offerings and the best practices and learnings from that pilot and roll out into our operating companies in Connecticut and New Hampshire. While we started with this somewhat limited number of offerings, we are trying to always look to see what other types of equipment we can integrate into our offering. We are always trying to balance scalability with customization.

Winterbottom: You have heard that the pilots and projects shared with you today are rather unique, but they do share quite a few characteristics in common. I have asked each of our panelists to speak a bit about which program characteristics they are most proud.

Ramkissoon: I think one of the cool factors for me in terms of our pilot and what I really appreciate is, first, it's very complex, but that makes it exciting. Second is, we could have designed this pilot in a vacuum. We could have put together a set of different rates, picked customers out of a hat, and just said, "Okay, let's go to market with it as is and test it." However, what I think was truly exciting about our pilot is the experimental mindset behind it that was a driver at each iteration.

Even designing which rates we were going to move forward with went through a process. When we were ready to go to market prior to launch, we went to customers first and we presented them with options about how you would want to be communicated with about new rates. We asked them: what type of images appeal to you? What types of channels do you prefer? What types of offers and messages are engaging to you? From those findings we created our marketing campaign and strategies, and then we went to market. Even now, we continue to iterate as we move through the pilot.

As I mentioned, we just launched the country's first Test and Learn Campaign for Rate Change, and I think the experimental design behind that is what makes it truly exciting. That is because we are doing a live test with customers in real time that is measuring how they respond to not only the actual rate, but the channels, the offers, and messaging that resonates with them about why they might want to participate in this plan. Seeing all of these components come together and unfold in real time with real customers is what makes it exciting for me.

Winterbottom: Candice, what program characteristics are you most proud of for Smart Home Rate?

Tsay: I think I am most proud of the rigorous research design that we are baking into the pilot, how we designed the program, and what we are doing today to implement. As I mentioned previously, we are running a randomized control trial, which will allow us to compare two different rates with different features in parallel. That is really exciting.

We worked with our research partner, Nexant, from the beginning, so we have been able to keep this research focus. I think that is critical in terms of helping to ensure rigorous and hopefully unambiguous results that we can use to make more evidence-based strategic decisions on rate designs, the value of DERs, and other important questions for the industry and our company as we look ahead to the future.

Sussman: I am pretty happy about 93% customer satisfaction on our pilot. Even though we are offering a compelling offer of a free device for customers, it does not guarantee that customer will like it or want it, which is a bit of a challenge because we're not fully there yet.

The fact that we are able to work with the contractors is a great benefit. We identified four different contractors that can do the installation. We originally designed the pilot so that the contractors would conduct direct outreach to customers. However, we changed it so that our implementation contractor helps coordinate which contractors work with which customers. Even though we are going into customers' homes, they seem to be welcoming us and our efforts to set up their devices. We see in our online portal that customers are actually using the device, including setting it up in learning mode and being able to set it on vacation mode.

I don't know why or how we have 79% response rate. I speculate we could be seeing those early adopters participating, if we look at the typical technology adoption curve. I do think that is important to keep that in mind. However, these customers can be very vocal about what they do or don't like. We haven't had any issues yet, but, again, we're not changing set points yet. So, that could change.

Goldman: For Eversource, I think one of the characteristics we are most proud of is this ability to offer a portfolio of solutions to our customers and really match the right technology to the customer need. For example, in the southern part of Massachusetts, we actually still have a pretty strong commercial fishing fleet, and that necessitates fish processing, which really means that you have to have cold storage.

Therefore, for a customer that was operating a cold storage facility down in New Bedford, Massachusetts, we could have offered them a lithium ion battery that maybe had a two or three-hour dispatch. But that actually wouldn't have been a very good fit for that type of customer. They have cold storage that needs to be cold all day. We were actually able to go in and offer them a thermal storage solution that was essentially able to negate the need for the customer to run their compressors for a much longer time period, while maintaining the right temperature in their cold storage facility. That's just one example of us being able to offer the right solution to the customer. That is what this portfolio approach has allowed us to do.

Winterbottom: You've all touched on customer research, but, for Eversource, how did customer research inform the development of your pilot?

Goldman: Customer research was absolutely critical in our demonstration projects. You may recall, earlier in the session, I began my presentation by showing some of the customer class research we did. We actually dug much deeper into that type of research. We pulled a random sample of about 300 customers and looked at their five-minute interval data and compared that to when the ISO New England system was peaking. We had a surprising discovery. We assumed that what is driving peak are these hot, humid days, when everybody is running the air conditioning full out. However, that is not at all what was happening.

Instead, we saw that the ISO New England peak apparently was really being driven by what I will call an "aggregation of shoulder peak." It is a situation where everybody is at 70% or 80% of their peak. However, when layered on top of each other, that's what was creating the ISO peak. We realized that we needed to find solutions that actually work for customers when they were only at 70% or 80% of their peak and they weren't running full out – when they weren't at their 100% of the peak.

With regard to customer research, the other dynamic that is happening in the New England region is that the peak hours are moving further and further back in the day. Therefore, finding solutions that customers could still use later in the day was critical. That type customer research is what led us to some of the solutions sets that we tested as part of our demonstration projects.

Winterbottom: Zach, what about Smart Gas Water Heater Pilot? How did customer research inform your approach to trade allies and partnerships, and the contractors that you're working with?

Sussman: We obtain customer research. Our market research team will reach out to customers. However, we're not the ones that are day-to-day working with the contractors. Con Edison has a residential implementation contractor, and we rely on them a lot to help keep us in the loop about what is going on with our customers.

We work with our implementation contractor to make sure that the contractors that they were bringing on board for this pilot could be trusted and could actually do the work, and then we made sure that they were trained in installing this technology. We didn't want to incur the risk of a random contractor. That said, we understand that a homeowner may have a specific plumber that they really want to work with, and that they have always worked with. However, we did not want that plumber to come in and potentially install the technology incorrectly, get the wrong readings, and then suddenly not have a working program. Overall, our approach so far has been pretty successful.

Winterbottom: Candice, what about the Smart Home Rate Pilot's approach to trade allies and partnerships? What have your lessons learned been?

Tsay: We have a number of different partnerships on this pilot. As one of our technology providers, we chose to work with Uplight, in large part because they have orientation around the customer experience, and I believe they measure success based on preserving customer comfort and keeping that satisfaction even as their air conditioning is being adjusted. That aspect of thinking in the shoes of a customer is really important in a demonstration project like ours.

We didn't rely on our own custom research on that aspect. We relied on Uplight, in their experience in other pilots to guide us there. However, we did use customer research conducted by our implementation contractor, ICF, in shaping our marketing and messaging campaigns for the pilot.

The Smart Home Rate project is all completely voluntary enrollment, and we're trying to enroll enough customers to get our sample sizes. Therefore, it was important for us to have messaging that resonated with them. We conducted focus group testing of different value propositions and landed on one that was centered on technology adoption. We fine-tuned our messaging to talk about how these new technologies in the home can help the customer manage their energy in new ways.

Winterbottom: Annie, in your introduction to the innovative pricing pilot, you spoke about the role of customer research in informing the messaging that you use for your recruitment. How else has customer research informed your pilot?

Ramkissoon: Customer research has been a big part of the pilot. I think it's a primary driver of the pilot. A large amount of our success on the pilot really depends on our ability to communicate with our customers. Not only in just communicating with them about a new plan, but really communicating to ensure they understand the new plan, the new pilot, and also that they can respond to us about it, and ultimately realize the value and benefits of demand rates, and be able to then take action from that.

Because we have placed such paramount importance on that, it was important for us to then understand what the best way is to do that. Similar to Candice's project, customer research and its influence on messaging and content has been very vital to our pilot's success. In terms of how we use customer research, I think it has been from beginning, during, and even after. Prior to even going to market, we conducted a lot of language testing on just how to talk about the rates, including what to call them. We needed to proactively answer questions like: what is the demand rate? What do customers think about that?

We did robust testing on questions like that in customer focus groups, and through surveys with the goal of creating a strategic messaging hierarchy that then guided us about how to talk to customers about demand rates. Using that approach, we then took it a step further knowing how to talk about the rates to making the rates exciting and motivating for customers to participate. And so, we did more focus groups for creative testing and content development, and that went through multiple rounds of testing.

Then, finally, we've gotten to the point where now we can actually put it on the market. But that in and of itself is a test. Through our Test and Learn, we're now seeing real-time responses to our content through our marketing.

Then, finally, I guess the last stop on the customer research train is really our surveys. We're still continuing to survey our customers after each milestone of the project. Whether it's through seasonal surveys or through any other pain points that are of interest to us, we're continuing to survey customers to ask them what do they think of the plan? What do they like about it? What do they not like about it? How satisfied are they? It's been very continuous for us, and we're continuing to learn and evolve as such.

Winterbottom: What's been most surprising?

Ramkissoon: There are a lot of surprises. I think one of the big surprises for me with this pilot is that, when I joined the team, a lot of the pilot was already developed, but despite the amount of progress we've made, we continue to learn something new at every turn. When you think you know, you don't know. You go to market and you learn something new.

For example, what was most surprising to me was that we went out thinking, "okay, customers are going to be like, 'Well, what's the demand rate? Tell me more. How does this rate work?'" What we found in our focus groups was that they really just wanted to know what the plan was, how it benefits them, and what do they have to do. That was it.

The learning? Keep it simple, keep it clear. Customers didn't care about the detailed overviews of how demand works and how do they count their peaks and off-peaks. They didn't want to get into the dirty details. That was surprising to me, because we're in this era of technology and information-savvy seekers. So, we thought they would want it all, but they didn't.

Winterbottom: What about the rest of our panelists? Any big surprises for you along the way?

Sussman: I'd say one surprise, especially when I look back to other pilots I've launched, is just the difficulty of getting 300 customers. We included in the marketing email that the technology is free. However, that clearly isn't enough for our customers to actually want to participate.

That being said, there was a time I tried conducting a study where I provided free smart home products at 24 homes, and we couldn't even get all 24 customers to sign up. I guess people can be a little hesitant if they see an email from Con Edison, or anyone else for that matter, saying, "Hey, here's this free thing." They're likely thinking, "what's the catch?"

People don't read emails. But we still have a 30% email open rate, so you would hope that we could at least get the 300 customers. Right now, we're looking at different marketing strategies that still include the email, but could include other approaches, like referrals and incentives. It worries me a little bit if we want to go to full market, but I think we'll figure out a way to get it to work.

Goldman: I think for us what was most surprising is, again, just how non-coincident a lot of our customer absolute peaks were with the ISO peak. In 2016 and 2017, as we dug into these 300 randomly sampled customers, only 25% of those customers had their absolute annual peak on the same day as the ISO peak, and only 1% of them peaked at the exact same hour as the ISO peak, which again is what drives those composite cost allocations. That really, I think, was a surprise to us and drove our mindset in terms of how we were going to go about developing these pilot projects.

Winterbottom: Mike, you mentioned that you're trying new things with your pilot. If you could think back to your planning stages, what would you do differently?

Goldman: Maybe this also goes into the surprising part, but at the outset of these demonstration projects, I didn't realize, as part of the team that was planning and developing the demonstration projects, how many other parts of the company this would end up touching.

If I could do it a little bit differently, it would probably be better or more advanced communication with other parts of the company. More specifically, making sure that we're getting the folks in the control room up to speed on what we're doing, because they may be responsible for ultimately dispatching some of these, or over-riding a dispatch if necessary, or making sure that the interconnection folks know that we're going to be offering an enhanced incentive, so that we might see more applications coming through, or the distribution engineering team, the IT team, cybersecurity. I mean we really ended up touching all of these different parts of the company. Just, I think, having better awareness throughout the company, in the organization about what we were doing and what was coming up, I think would have done that a little bit differently.

Winterbottom: Zach, how are you adjusting plans based on what you've learned so far?

Sussman: We're still in the installation recruitment phase, so the main one is what other means of recruitment can we do? Originally, we were targeting AMI gas customers in Westchester. That's a small pool. Knowing those are our main targets, we have to ask: what's next? The next group is going to be gas customers that have an email address that are not AMI customers. Then we'd likely expand to some more customers that don't have email. For those customers, we will send them a letter.

When we look at recruitment, I always try to start with the most targeted group we can use. Then, I work our way out to thinking if we need to email all gas customers in Westchester? We'd rather not. I don't think we'll need to, but that's how we're adjusting, trying to understand how and why people are signing up, who is signing up, and then try to use that to target future customers.

Winterbottom: Candice, would you have done anything differently looking back now?

Tsay: I'd just echo what Mike was saying about how doing projects like these, there's a lot of internal coordination that's involved. This is more of a "what we did right," I think, that was effective.

Early on, as part of the governance structure for the rate pilots, we were able to establish a steering committee. So, we have internal stakeholders at the decision-making level be part of this committee and have different departments that we'd be relying on and we'd have very extensive touch points with throughout the implementation of the project as part of the committee. That includes IT, billing, customer outreach, communications and public affairs, rate engineering, and many more.

Having that committee and their feedback and keeping them in the loop as we implement these projects was pretty important. If we didn't have that, it'd be a lot more difficult to just get past all these different roadblocks that you can run into in an organization where everyone is very focused on what they do on the day-to-day for a project like this. The committee breaks that apart and provides a structure to run that coordination through.

Ramkissoon: From a design perspective, we've done a lot of research. If I had to go back in time, I think what I would have done differently, or maybe just go back earlier, is just bring a customer centric approach to the rate design. We've learned after the fact what customers are motivated by, but I think we could have brought them in and just welcomed them to the conversation, "come co-create rates with us. Tell us what you'd like to see in a rate."

We could then use that to help us weigh the company's interests versus their wants and desires. Then we could have been a lot more meaningful in our conversations with them about these rates. That would have had a very different experience in our path forward.

Winterbottom: Getting customers to adopt to these new rates is really intrinsic to your pilot. Rates and technology and adoption is key to the other panelists' pilots as well. What do you think has been most persuasive in getting them to adopt the new rates?

Ramkissoon: The success of it is just the marketing. It's been really powerful. We've put a lot of resources into developing it and fine-tuning it as we go. I think that our ability to communicate with customers about a new plan and how it benefits them, really focus on the customer, has been valuable in helping them see the benefit of this plan, and really ease any friction in giving it a try.

I think, to Zach's point earlier, getting something from Con Edison isn't always the most magical moment. So, for them to really give us the benefit of the doubt and want to try this plan, I think, has been very driven by our motivational marketing.

The other piece that makes it a little more attractive for customers too is we do offer a one-year price guarantee to pilot participants. The way that works is that, if a customer's bills would have been lower on their previous plan, we'll credit them the difference at the end of the first year. I think that brought customers a peace of mind and really allowed them to try the plan for first year with no risk. I think that's why they've been so receptive to giving the plan a try and really giving it their all-out effort.

Winterbottom: Zach, what about you? What do you think has worked the best so far? What value propositions have you used?

Sussman: The value proposition with the customers is a cool new toy. Hopefully, it should sell itself. We've gone too far down the road to understand how the actual algorithm is working to optimize the water heater. I'm hoping that we don't have the issue of customers wanting to drop out because of a situation like this: it's 2:00 in the morning, the customer has to get up to go to the airport, and the water heater doesn't realize that they're going to be awake, and it's a cold shower. Hopefully the customer sees it as a new device that lets you control your home. I was talking to a customer once and they said that they liked being part of pilots. That is our customer.

We have to really convince customers to want to be part of the pilot. I think the draw is that free technology. I think you can see that when you look at the number of smart thermostats that are out there and how much adoption there is with smart lighting, smart speakers, and everything else smart.

Well, water heaters are one thing that you're not going to find as smart as easily. It's also a longer-term device. Thermostats are $150 or $200. That's something that's easy enough that you could always just replace it if you aren't happy with it. The water heater, the fridge…these large appliances that have a 10- to 20-year useful life. If your water heater dies, are you going to just go ahead and get a new smart one? Are you going to wait for the contractor to say, "Yeah, I'll get a smart one and stop"?

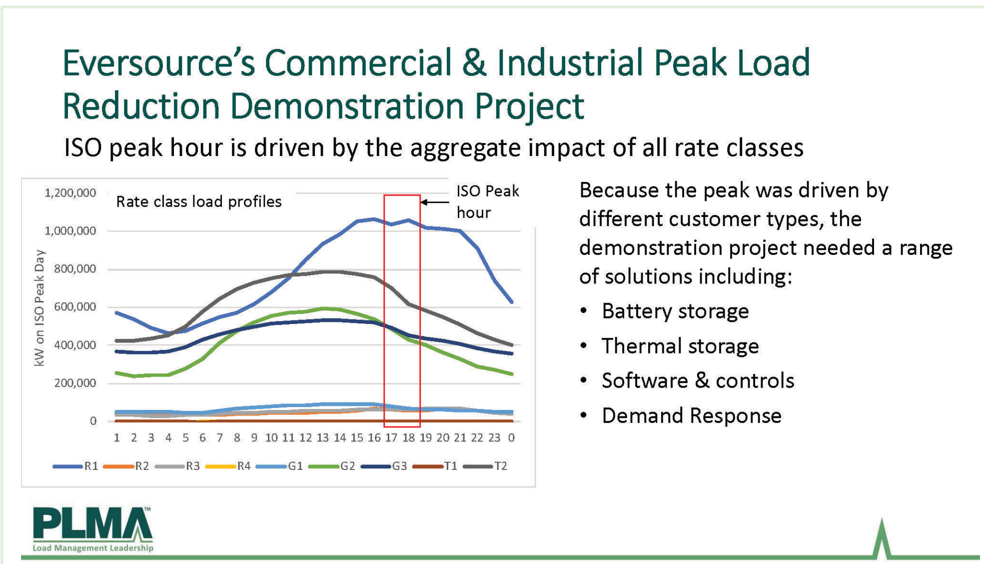
Winterbottom: Mike, what about you with such a varied customer base that you're outreaching to? I would imagine the customer value proposition is customized for each type of industry or business. How do you approach that?

Goldman: Yeah, in some ways it's customized, but in some ways it's somewhat standard as well, because we're really going after some of our larger customers that are on time of use rates that have demand charges. I think, for us, explaining the value proposition was really actually outlining each individual value stream that our projects could help them achieve.

There could be things like the incentive directly from our program to help with the installation of the equipment. It could be mitigating their own capacity tag allocations. It could be participation in the wholesale market as another way to generate revenue. It could be things like demand charge avoidance. However, also because some of these are our largest, more institutional customers, a lot of them have their own sustainability initiatives. So, aligning what we were doing with their own sustainability initiatives I think really got us a lot of buy-in as well.

Winterbottom: Any final thoughts that the panelists would like to share?

Goldman: Just one final thought, from my perspective, is, as you're designing these programs or as you're thinking about it, really make sure you're articulating what problem you're trying to solve. I just think it makes it so much easier and it's a more logical approach to it. It also helps with things like metrics and how you're going to understand whether or not you're successful with these projects. If you can outline the problem, you can



SLIDE 19 View Slide at: https://bit.ly/2v9x4yK

develop the program around it. Then you can also develop the metrics for success. That's something that we've found to be particularly effective.

Sussman: To piggyback on that, I don't think utilities are the greatest in the world of actually understanding the customer. I think we're trying to do a lot better at that, and I'd like to think that the four of us are up here because we are doing that, but you need to know your customer. You need to actually understand how you're impacting them. They're not a rate payer, they're a customer. We need to make sure that we actually think about how we're impacting them and what the value proposition is for them rather than for us. If we can make them want it, then it's a resource for us.

Tsay: I echo some of the other things that the other panelists have said about these being demonstration projects and paying attention to what the customer wants. We thought about that every step of the way in how we're going to implement this pilot because, ultimately, doing this isn't very helpful or useful unless the customers end up embracing what you're doing. You want them to participate. So, paying attention to that, I think, is just a key aspect of designing these types of programs.

Ramkissoon: In addition to everything they've all said, I think they made valid points that it is important to know your customer. I think the other part of it too is it comes down to creating something so impactful, and we really want to prove it. We want to make sure it works. To Candice's point, what's the point if the customers don't buy into this? I think we create so much pressure for this to be successful.

I think one of the key things about the pilot, and when you run pilots in general, is you have to have room and flexibility for failure and for learnings. I think part of that is very unconventional for us as utilities to work within a culture where it can seem like failure is not an option. But, in some cases, we do have to plan for that where we can afford to make some mistakes and learn from them, and be comfortable working with uncertainty, and working with larger groups that are going to be very skeptical of this process. Ultimately, I think it's also about creating a culture where it's safe to work within ambiguity and bring people along with you to really motivate them to take that challenge with you and just jump into it.

Winterbottom: Great.

Sussman: Yeah, failure is an option.

Winterbottom: Failure is an option.

Sussman: And fail fast. I mean that's what our director of R&D and their director would say, and it makes a lot of sense.

Paul Miles: Paul Miles, PECO. Many of us have implemented programs and have faced many of the challenges and opportunities you've talked about today. My question would be directed towards Mike because he's the outlier with doing a wider swathe of customers involving what I perceive to be really all-customer classes, if that's correct.

Goldman: Yeah.

Miles: While I heard you say the words, and they just flowed nicely, what kept coming up in my mind was dollar signs. Batteries are not cheap. Thermal storage is not cheap. Can you just speak briefly about some of the challenges and how those were funded? How did you make that all come together?

Goldman: Because these were demonstration projects, there wasn't necessarily a requirement to be cost-effective. We had a bunch of research questions that we were trying to answer. So, we provided a large incentive for customers to install that equipment so we could start answering some of our research objectives.

But on an ongoing forward basis, what we've decided to implement is more of a pay-for-performance program design where we can essentially set the incentive level at a spot that makes it cost-effective. We do have an elevated incentive level for battery storage versus more manual curtailment because we think we can actually derive more value out of it. We can dispatch it more often. It has other characteristics that essentially make it more valuable. But at the end of the day, I think we would differentiate between the dollars and the reasoning behind the demonstration projects and the dollars and the reasoning at a full programmatic scale up.

Susan Marinelli: Susan Marinelli with Pepco Holdings. I'm not familiar with your regulatory constructs, but what is the funding mechanism to allow these pilots? Then what type of reporting do you have to do to the commission or something like that?

Ramkissoon: With the mass market rate pilot specifically for Con Edison, we designed our rates to be revenue-neutral, so we're able to recover the costs through other mechanisms.

In terms of our reporting, especially to our public service commission, we've been very, I would say, joined with them from the beginning of pilot conception. We've been talking with them and collaborating with them, so we've had a lot of deep engagements with their rates group, as well as their customer groups. We've kept them part of the conversation and they had a seat at the table with us. We brought them on the journey with us.

Formally, we are required to file a quarterly report with them, in which case we're reporting on our outcome-based metrics, which are essentially the enrollment rates, as well as any survey feedback that we're hearing, and bill and load impacts when they're available. But it's really just an ongoing conversation, and we keep our lines of communication open with them.

Tsay: Con Edison is a New York utility. About five years ago, about the time I joined the company, the New York State Public Service Commission basically told utilities that, "you guys are not innovative enough," and, "you guys need to start offering more choice and different types of services to customers."

Part of that evolution has involved mechanisms called the REV demonstration projects, which the commission has said, "we'll fund these projects and give utility companies the freedom and flexibility that's needed to make them learn how to be more innovative." That also meant the regulators themselves stepping back from the process as well, because it's hard to be agile. It's hard to be innovative when you have to do all the usual utility regulator dance around developing new programs.

At Con Edison, we really try to take full advantage of that space that we're given to do innovative things and explore different models and have that type of funding mechanism in place. If you're in a state with a regulator that wants to be very progressive, I guess that's the formula.

Sussman: Within energy efficiency, let's say maybe half of our portfolio is rate-based and the other half is funded through the systems benefits charge, which is on the bill. The water heater pilot is under the systems benefits charge. Within that portfolio, we actually have a carve-out for what we call Test and Learn Electric and Test and Learn Gas.

We don't have to be cost-effective. We just need to show that we could be on a path of cost-effectiveness or not at all. That lets us have some wiggle room to really try things out.

In terms of reporting, I guess as a department, we report out to a regulator. But with the pilots, we don't really report as much. We did have that carve-out for Test and Learn where they said, "You need to figure stuff out. Go ahead, figure this out. You have a pool of money. You're just not going to claim savings." So that doesn't help with our savings numbers.

Speaker 11: My question is maybe a good closing question. These are all pilots. Assuming success, what are the right sign posts to watch to see these become more than just pilots?

Sussman: Cost-effectiveness. You're going to have a larger upfront cost, leverage that as a pilot, but then try to figure out how you can actually get the unit costs down. It comes back down to the Benefit-Cost Analysis. What are the benefits that your pilot is providing and what is the cost and can you get it to one or better? And customer satisfaction. If no one actually wants it, then it's not going to go anywhere.

Ramkissoon: To Zach's point, for us, it's customer acceptance and satisfaction. If they're not adopting these new rates and they're not satisfied with them, then it's very likely it's not going to make it out in a mass market rate design.

Presentation slides available at https://bit.ly/2RKmW7b

Introducing New Rates with Help from Dr Seuss

From 40th PLMA Conference

Ahmad Faruqui
The Brattle Group

Joel Gilbert
Apogee Interactive

Richard Philip: This presentation will continue on the topic of pricing and elasticities and how customers can and should we reacting to them, as opposed to walk them through a pilot and some of the other things that we've been talking about today. This is an opportunity to address it in a slightly different way. It's my distinct pleasure to introduce two gentlemen that are really, as far as I'm concerned, giants in this industry that have been people that I want, that are thought leaders and people that I've been reading and following throughout my short 36 years in this electric utility business.

First, here to my left is Joel Gilbert. Joel is the president and chief software architect and cofounder of Apogee Interactive. He personally directs the design and development of energy analysis applications utilizing the highest standards in building science, engineering, operational patterns, weather data, and pricing to ensure analytical integrity. Between Joel and Dr. Faruqui, they have worked with virtually every utility in North America, particularly in the United States and Canada, and Joel has worked across every organization that's of influence and trying to lead change and how we think about where we're going in the future. And I can tell you that the utility that still serves this building still does not have its rates correctly aligned with its costs and giving customers the right price signals.

Sitting to Joel's left is Ahmad Faruqui with The Brattle Group. He is, as far as I'm concerned, the foremost expert on utility rates and tariffs and giving price signals to customers around how they use energy. Again, he has worked with virtually every utility. He's worked literally around the world on these topics. He's given seminars on all six continents. Both these gentlemen are extensively published - books, articles, papers, and the like. And so, it's a great opportunity to have people of this much horsepower to talk about this. But we're going to address it in a slightly different manner. We're going to get your attention with a favorite book of mine that I remember reading to my little sister a short 50 years ago. And then we're going to go more into why this whole idea of flexible rates and time differentiated rates and so forth is not a scary thing. It's the necessary thing.

Joel Gilbert: So how many of you either have or currently read Green Eggs and Ham to your kids? I think most people. You are familiar with the Dr. Seuss book? There were two that were our favorites with our son. It was a One Fish, Two Fish, Red Fish, Blue Fish, and he seemed to enjoy that one more than Green Eggs and Ham. And I think very simply the idea of Green Eggs and Ham, just the words themselves kind of make you go, eh, I ain't doing that. And the reason I picked it was that when we look at rate design and we look at this transition with consumers, customers, we have this initial reaction that I ain't doing that. I can just see disaster and whatever. And so, the theme of this morning together, and I'm so privileged to have Ahmad joining me on this, is to take a look at this that it isn't the green monster. It does actually work and I'm going to open it up by just a parody. I only have about a minute of reading what actually Susan helped me rewrite, which is Green Eggs and Ham as if we were a utility person and talking to our senior leadership. So, bear with me. It's a little silly, but it's only a minute so put up with it.

I am Sam. Sam-I-Am. That Sam-I-Am. I do not like that Sam-I-Am. Do you like your new rate plan? I do not like it Sam-I-Am. I do not like the new rate plan. Would you like it here or there? Would you like it as a dare? I would not like it here or there. I would not take it as a dare. Do you think I really care? Going back to our early presenter. Would you, could you, shave your peak? No, I will not shave my peak. It's not low prices that I seek. Would you like it timed or peaked? No, I would not like it timed or peaked. I would not like it changed or tweaked. I do not like your new rate plan. I do not like it, Sam-I-Am. Well, would you, could you use a fan? No, I would not use a fan. I will not, will not though I can. I do not want to shave my peak. It's not low prices that I seek. I do not want your special rate. I will not take your bait. I do not like your new rate plan. I do not like it, Sam-I-Am.

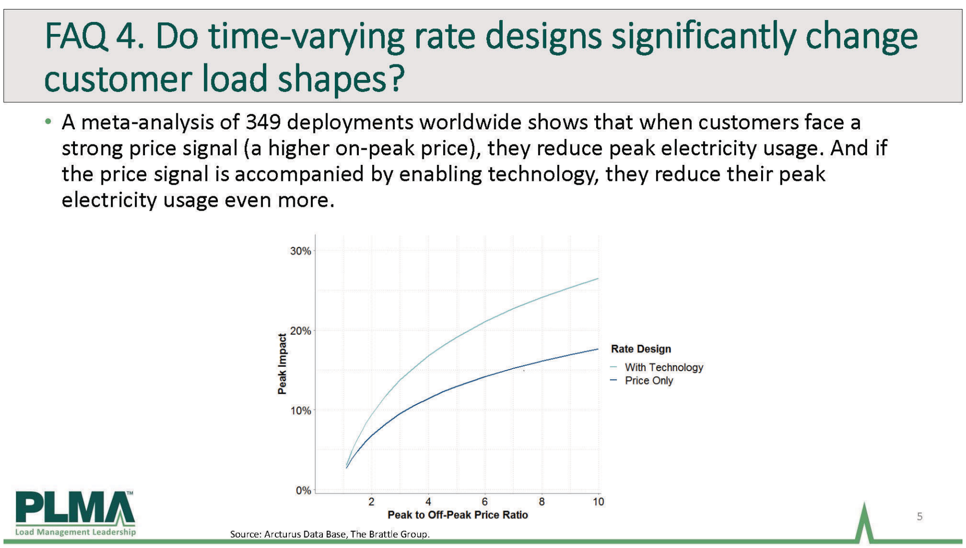
Well, would you, could you for your home? Would you try it when you roam? Try it, try it. You will see. This new rate plan will set you free. You do not like it so you say. But try it, try it and you may. Try it, try it, anyway. All right. If you let me be, I will try it, you will see. Say, I like your new rate plan. I do. I like it, Sam-I-Am. I would do it here or there. I would do it as a dare. I didn't know that I don't care. I would like it timed or peaked. I would like it changed or tweaked. I would like to save some cash. It doesn't sound extreme or rash. I would like to shave my peak. It's not savings that I seek. I so like your new rate plan. Thank you, thank you, Sam-I-Am.

And this transition that scares us is what I'd like Ahmad to now share with you the worldwide experience of the single person who when most people hear of rates and rate transformation in the world, only one name comes to mind. And that's Ahmad.

Ahmad Faruqui: I think you missed your true calling as a Shakespearean actor.

Gilbert: Right. I hope not.

Faruqui: It's a bit late to change. So in terms of my opening comment, I'm reminded of a talk that I gave in New Mexico at a regulatory conference where the chair of a state commission introduced me with these words: "This man," referring to me, "is going to talk about time of use rates, and I can tell you all in the audience that if I go on a time of use rate, my wife will divorce me." With that introduction, what was I supposed to say? He dared me. So, I just looked at him and I said, "Well, she's probably going to divorce you anyway. Why blame it on the time of use rate?" You should have seen the expression on his face. I never saw him again. I never testified in that state. And life was good.



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It is certainly a very contentious career that I embarked upon in 1979 in the EPRI Rate Design study. I had no idea what rates were. I had no plan to become a rate economist. I did not even know there was such a thing as a rate economist. But 40 years have come and gone, and I have become a rate economist. Now I know what they are. In the beginning, I thought a long and boring and tedious career lay ahead of me. Well, I have been threatened with bodily injury in some of my rate case testimonies. I have spoken in hearing rooms surrounded by SWAT police and policemen armed with Glock pistols. I was asked once if I ever hesitate to turn the key in my car. And I said, "Why would I do that?" And the person said, "Did you see the movie Casino with Robert de Niro?' I said, "Is that something I should see?" He said, "Maybe you shouldn't." So, it is a very, very cosmic struggle. And if you're trying to propose rate changes and you're testifying on behalf of the utilities, which for better or for worse, I have been for the last 10 years or so, you're viewed as Mr. Evil. You are viewed as the incarnation of Satan, the devil who was going to lead married couples to divorce each other and cause havoc to break out among low income communities, senior citizens. And I have become a senior citizen myself and know how they feel.

There are challenges, there is no doubt, but pilot after pilot has shown that results confirm what we always knew when we did our Econ 1A class which is basically that people respond to price. And whether it's groceries or renting a car or shopping at Macy's, people are price-sensitive. And so, the counter statement that's always been made to me is: Electricity is different, it's a necessity and it is not governed by the laws of demand and supply. Well. That's why 349 pilots have been done to prove over and over again that electricity is not anything different from anything else out there. There is a budget, there's a lifestyle, there's a trade-off to make. A third of the people are not interested in saving money. A third are interested in saving money, and a third could be persuaded to save money by modifying their life-style. There you have it. So yes, that person's wife probably was going to divorce him because they were not interested in saving money. They were interested in saving their marriage and I don't blame them. The reality is that the choices are not so stark for most consumers. He said, "She will say to me that I am not going to do my laundry at 2:00 AM." Well, no one should have to do their laundry at that hour. We have smart technologies and laundry, by the way, is not even the biggest end use in your electricity budget. Plus, the new machines come with delay switches, as do dishwashers.

Now I will walk you through my slides. I am going to answer some frequently asked questions to stimulate your thinking and maybe respond to a question or two. Then we can chat more over lunch.

The first question is what are the main features of advanced rate design? Well, it should be cost reflective. It shouldn't be arbitrary. A utility is a natural monopoly. Whether it's Duke Energy or it's Pacific Gas and Electric or any other utility, it's regulated. It's not competitive in the traditional sense of the term. So, rate design has to reflect the cost structure.

Secondly, it should allow customers to manage their bills. It should give them an opportunity to do something to reduce their bill. I have yet to meet somebody who wants to pay more. Even in the Pacific Northwest where prices are already low customers want the rates to be even lower. It's just a human calling, the urge to save money.

Third, distributed energy resources are now the talk of the town, and certainly this conference has discussed a number of those DERs. So, pricing design should incentivize prosumer behavior even though right now initially there is a split in the industry. Some utilities don't like serving prosumers under Net Energy Metering because they don't pay their full cost of service and the deficiency has to be recovered from other customers. But in the long term we will be all prosumers. I have worked with many utilities on the topic. All of the rate managers that I have worked with have privately told me that they are prosumers. I am one myself. So that's the truth in advertising. Ultimately that's where society is going. Electric cars, solar on the roof, battery storage, digital thermostat, digital appliances, WiFi, all of those things.

And finally, it is about choice. I think we saw on one of the slides from one of the previous speakers that at one end you have the fixed bill or the Netflix pricing product. On the other, you have the peer-to-peer trading option based on transactive energy and real time pricing. And in between are other options. We have to provide choices to customers. That's the first question.

The second question is are there any tradeoffs in rate design? And sure enough, there are a lot of tradeoffs. Professor James C. Bonbright is a name that some of you might recognize. He wrote a textbook in 1961 called The Principles of Public Utility Rate Making, and that's the book that is cited in every rate case. Have you discovered it in your new journey? It's hard to avoid. It's boring as hell. The first time I read it was when I was 26 years old, fresh out of graduate school. I fell asleep. I did not want to read it for 20 years but it is the foundation of much rate work and as I began to testify in the rates arena, I made time to read it. And you cannot just use Bonbright. You have to look at customer considerations, like who are the losers, who are the winners? How do you make the transition easier for those who might see otherwise a higher bill?

This is something just for reference. There are several kinds of advanced rate designs all the way from the fixed bill to real-time pricing, and several items in between. So, there is no shortage of innovation and ideas and most of these, by the way, have been tested on people living normal lives. These are not just things invented by economists in the classroom. What we sometimes have been accused of doing is, oh, you're trying to bring an Econ 1A into the rate making arena. No, we have experience with hundreds of thousands of customers on these rates.

And then comes the ultimate question: do customers change their behavior when prices change? As we were discussing earlier, yes, they do. Each customer is different though. I think what I really liked about your approach in this case study is it will be individualized to each customer's lifestyle. That's the ultimate goal that we should have, but it's not easy as I'm sure you will agree. It is we are not there yet, but even if you have prices that are not varying by customer, which might be the ultimate goal, you still find, so I'm showing two graphs here. On the horizontal axis, first of all, is the peak to off-peak price ratio. This is time of use rate, critical peak pricing rate, dynamic pricing rates. On the vertical axis is the reduction in peak load that occurs in response to that price ratio. And I call it the arc of price response. It looks like an arc. And then I ran into an economist who said to me, "Oh, so Brattle pays you all that money so you can call the demand curve the arc of price response? Is that what really is all about?" I said, "I realize just the demand curve turned upside down. But most people who are not economists don't like to hear the term demand curve." So, this is an easier concept to relate to. At least that was my attempt in making it simple.

So what you have is these are regression analysis from 350 pilots summarized in these two arcs. There's a lot of scatter behind there which I'm not showing you. So, the curve below is simply the price by itself without any smart thermostat or any of the technology coming in. So, if you have a price ratio, let's say, of five to one, you're going to see a drop of about 13% in the peak demand without any technology. And then if you add enabling technology, you're going to get a lot more response, which is what you would expect. And technologies are becoming smarter by the day. So that technology curve is going to rise higher and higher.

So, is anyone offering these modern rate designs? Yes. We have lots of examples here. They are being offered throughout the country and I've had the privilege of working with clients in five continents. These rates are being offered in Australia and New Zealand and Asia and in Europe and in Africa, where real-time pricing originated for large mining customers. So, you will see they're proliferating everywhere. They reflect the varying cost structure of peak versus off peak. And they also reflect the fact that a utility is not selling something called electricity, even though there's one term is selling capacity as well as energy. So, it's a question of how do you capture capacity costs in the energy charges? Should there be a demand charge? Should it be coincident? Should it be over one hour or 30 minutes? All of those issues. And by the way, people say to me, "Oh no, residential customer has a demand charge today." I said, "No, there are 61. We have documented them offering demand charges and time-varying energy rates." So, there is a lot of movement happening. It's just that some of the regulatory audiences are not familiar with it. So, if you file a rate case, you have to cite what's happening elsewhere in order for it to have some traction.

Number six, so have customers accepted? Ultimately, the whole goal is about customer acceptance and you will see on the right column, acceptance rates range from 20% to 80%, depending on where the rate is opt in or opt out. And opt in is basically you have an invitation to the customer to sign up. If they want to sign up, fine. If they don't, that's okay. Opt out is what SMUD, for example, has done. Everybody is defaulted onto the new tariff. Of course, you have to educate them and prepare them. When I was driving to Sacramento one time, actually, I was stunned to see a billboard, which I haven't ever seen anywhere else, which said time of use rates are coming. I almost wanted to take a picture with my phone, but I was driving 65 miles per hour and there was no one else in the car and the camera was not automated to take a shot, so I asked them to send it to me from the website.

And Oklahoma Gas and Electric, they don't leave it just to the billboards. They have murals around their main building. If you've been to Oklahoma City and you've seen the building, you know what I mean. They have large murals, four, on one on each side of the four sides of the building showing how people are living normal lives with their Smart Hours program, which is a variable peak pricing program. So, with all of those techniques, you can expect a lot of excitement.

And then comes the big question of how do I make the transition? And now, people at that point say, like I was told in Texas just a few months ago, wait another five years, that was by a former commissioner, very well-known. I will not take his name, who I have known for a long time, who attends the meetings of the Harvard Electricity Policy Group. He knows exactly what needs to be done. I said, "Why wait five years?" He said, "We have a new legislature." I said, "In five years you'll probably have another new legislature." I said, "I've been hearing that for 40 years. When are those five years ever going to come within our grasp?" It's sort of like tantalizing prospect. So how do I get there? How do I turn the key in the car?

So, what you have is begin by educating and informing customers, and before the customers, of course, I don't have it there, you have to inform and educate the regulators and the stakeholders. Unless you do that homework, nothing will happen. Do the pilots. Do the field testing. And then offer these rates on an opt in basis. At some point make one of them the default rate. You have to move. Today, the volume metric flat rate is the default rate. A lot of people say to me, "There should be no default rates," but that's about the future. But you already have one today. You just need to realize it is like the man who didn't know what prose meant and he asked somebody, "What is the meaning of prose?" And he was a man in his forties. So, the philosopher said to him, "Prose is what you have been speaking your entire life." The default rate is the volume metric rate that you've had. All we are trying to do is move you to a more cost reflective tariff that will induce more efficient consumer behavior and lower costs for everyone. That's all we're trying to do.

It takes courage to do it. California SMUD is the first one. The IOUs are coming next. Do we have anyone here from the California utilities? Okay. So, I guess some of us in the room, Greg Wikler and I, are customers of California utilities and I can tell you that it's coming for all customers of the investor owned utilities in California. It only took them 19 years to get there. The energy crisis was in 2000-2001. Michael Peevey was the assigned commissioner. Later he became the president of the CPUC. He issued a ruling to look at advanced pricing, demand response, and smart meters. And now, 2020, it'll come. But the way it's coming, it'll be so mild that it'll be milder than Dove soap.

And so, the big question is what is that going to do? That's the big question. And I asked one of the utilities, why are you doing this? This will just cause, like Puget Sound Energy did that in 2001. Their time of use rate was so mild. It was 15% higher on peak, and 15% lower off peak. And people were told to shift, shift, and shift, and they shifted, shifted, shifted, and shifted. At the end of the first year, they saved $1, $2 and $3. Some lost 50 cents and others lost a dollar. They were furious. Revolt was in the air when the new CEO arrived. He ended the program despite being an advocate of smart rate design going back to his early days at PG&E where I had first met him.

So, the case of unrealistic expectations is what the story's about. I'm really concerned about California. I'm trying to raise that issue. I have been told, "Oh, it's not about saving money." I said, "What is it about?" She said, "It's about saving the planet." I said, "How would you save the planet with a rate that doesn't cause anyone to change their behavior?" She said, "That's for you to figure out."

Okay, so make one of them the default rate, but please don't do what California is doing. And supplement the rate designs with enabling technologies. So, there are a whole bunch of papers behind it that summarize the story. And with that, I'm going to turn it back to Joel.

Gilbert: We're going to end on this flow diagram. This is a roadmap for everybody here in terms of what you should think about on these rate designs. Very simply, working with one client here, their concern was in the demand rate, the low consumption customers, which are not low income necessarily, low income are a different group. Low consumption, people who don't use very many kilowatt hours, you might say typically five to 700 in a month or something like that. They're relatively low consumption, at least here in the Southeast. What's going to happen to them on that rate? Well, you can start breaking them into basically groups that are going to either fully benefit, meaning that they become what we would call winners, and there are some who frankly are going to be disbenefited, which is the nice, politically correct word for losers. And then there are people who are winners, but there could be optics where they might indeed seasonally look like losers, which Brian Pippin talked about yesterday on his talk about when they launched their Rate on Demand.

And it was very important if you were here and listening to Brian. He talked about launching it deliberately during the higher kilowatt hour consumption periods, because on a demand rate in general, almost everybody is a loser. However, in life there are losers. And I don't mean that personally. I'm talking about there are people, when you change the pricing system, they're going to disbenefit. Therefore, rather than just let them go to the commission or the radio station or get on social media, we should, as an industry, identify them before the deed we transition them, and now we have choices. One of which might be ouch, they put in technology we used to add advance and advocate. And now on this new rate, we wish they hadn't.

Let me give you the biggest single one that you should worry about. And that is an instantaneous electric water heater. And so if at any time in your past you were an advocate of an instantaneous electric water heater, because somehow your rate department said, we don't care, we've got capacity and you put them in, that customer could be truly disbenefited by this rate. So, they would be technically grandfathered into be this, because after all, this is not a customer choice issue. So, leave that alone.

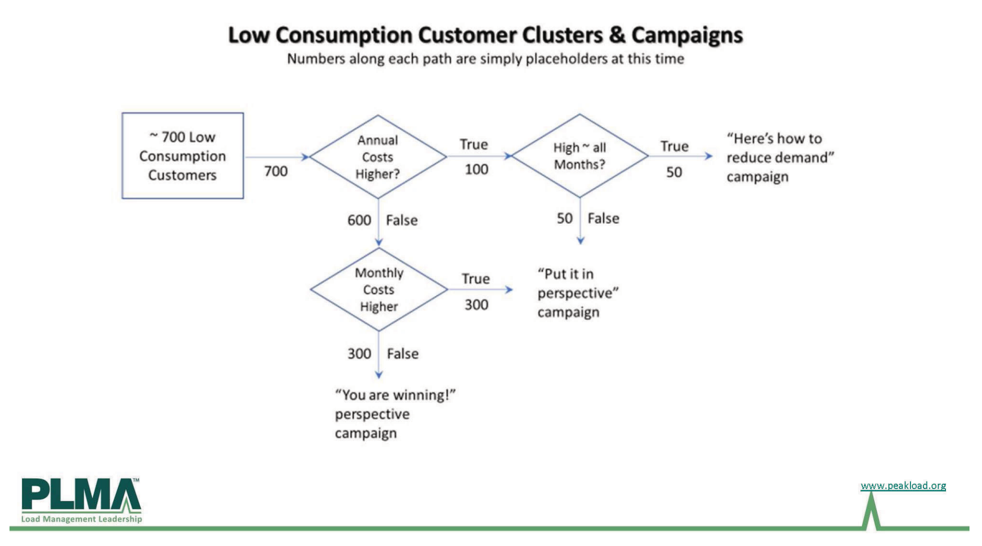
But there are other customers who might lose on this new rate. While your choice is education and communication, you certainly don't want to go into this and just hope, maybe they won't notice. Your point is you identify them, and you go indeed and get ahead of the curve by showing them choice, showing them how to do what they need to do. That's probably a small group. The winners are no problem. You want to pat them on the back for being a winner.

The one that I want to point out is the middle group, and that's the one where sometimes in the year they benefit and sometimes they don't. We really need a special campaign for those kinds of people, because depending on when you're starting your program, you could literally be starting at the worst possible time. You could be starting during a disbenefit period and you must let them know they're about to do better and keep it in perspective with the kind of communication. Now again, I'm not trying to design your program and I know this is a busy slide, but I think everybody in the room by the nodding of the heads understand that this is our responsibility. Customers will figure this out the wrong way. We have got to be proactive and outbound and communicate to them. At that point, I think we're going to open it up to questions.

Dave Erickson: Dave Erickson, New Hampshire Electric Cooperative. You didn't talk at all about net energy metering. I mean, you mentioned incentivizing DERs. I hope you didn't mean subsidizing DERs. One of the things that we're kind of trying to focus on is accurately valuing the electrons that get produced from behind the meter generator basically. How would you suggest doing that in a way that doesn't completely disincentivize, or is there a way? Because basically we're competing against the cost of wholesale power basically minus losses and things like that. So, what would you suggest in terms of a fair way of valuing these electrons?

Faruqui: That's is really the $64 million question today in so many rate cases throughout the 50 States. There are three things that come to mind. First of all, there is a 30% income tax credit on the installation of solar. I know it's going to go down to 26% next year, but 257 mayors have written to Congress to please extend it, so it stays at 30%. We'll see how it plays out.

In addition, some states and some local governments provide additional rebates to offset the cost of the solar investment that the customer is making. None of that is going away. It's up to the governments, up to the utilities if they want to, like in Texas they have in the City of Austin, the City of San Antonio, pretty strong localized rebates if you will. So, there is that whole rebate paraphernalia that is out there.



SLIDE 21 View Slide at: https://bit.ly/2TKilVc

However, there is the challenge of the cross subsidy that you brought out between customers. In the volumetric rate that exists today for residential consumers there's a huge cross subsidy between solar and non-solar customers because when the solar customer exports power to the grid, he or she gets compensated not just for the energy, but also for the transmission and distribution costs they haven't offset. That is the cross subsidy. States such as Arizona, California, Idaho, Kansas, and Nevada have been looking at that issue. And what they have said is we are going to change the rate design for the solar customers so that when their usage drops by 50%, but their costs do not drop by 50%, their bill is not going to drop by 50%, but drop perhaps by 30%. The volume metric portion of the cost that they have offset, they are rightly going to save. But they will not be getting any money on the capacity cost that hasn't changed.

Clearly when you change that rate design from a flat volumetric rate to a three-part rate, for example, or a time-of-use rate, you're not going to save as much. And so, there's a huge increase in the solar community. And we have seen that over and over again. So, the way to do it is first of all grandfather the existing solar customers. I was told in many cases, like in Nevada, to not use the word grandfathering. They said it was verboten (German: forbidden). And of course, the Salt River Project in the end during the prior year allowed grandfathering to be done. As an economist, I could be persuaded not to do it, and perhaps for no other technology that I buy, like if I buy a car that's very big and the price of gasoline goes up, suddenly I have a grandfathering issue. But nobody that I know has their car grandfathered because the price of gasoline went up or down.

So, you have to grandfather the existing solar customers because of the politics. You can still provide rebates to offset the savings lost to the customer. You can raise the rebates if you think there is justification for doing it on the basis of your avoided energy and capacity cost, just like an energy efficiency program. It still has to pass the TRC test.

Gilbert: I'm going to give you where I think we are as an industry compared to where consumers are. We are mambypamby, afraid of anything, and we are not really up to where the consumers are in terms of how engaged and interested they are. Let me take you into my life. I bought a Tesla, four almost five years ago now, and when I bought it, I thought I was going to save money on gasoline, because after all, that was part of it. Now, nobody buys a Tesla to save money. At least my Tesla S. My point is, my tag for my car has a $200 premium on it now because I own an electric vehicle and everybody else is driving a gasoline. I'm not paying my fair share of the roads. I would like you to memorize these words because they apply on the solar issue.

Grandfathering is fine. I'm not disagreeing with that, but I'm saying we have to start speaking our mind about what we're trying to do with all of this, which is to preserve equity, and also plan for a future by reflecting our costs in our prices. We are not bold enough in front of customers to use the examples of even electric vehicles to let them begin to assimilate and educate them on our social and mutual responsibilities. We are too much wimps.

Presentation slides available at https://bit.ly/2TNYkNM

Moving from Single "Cylinders of Excellence" to an Integrated and Finely Tuned Engine

From 40th PLMA Conference


Brett Feldman
Navigant


Justin Chamberlain
CPS Energy


Paul Wassink
National Grid


Greg Wikler
AESP


Mathew Sachs
CPower Energy Management


Moderator
Jenny Roehm
Schneider Electric


Moderator
Olivia Patterson
Opinion Dynamics

Jenny Roehm: Anybody who knows Mark Martinez, knows about cylinders of excellence. We at PLMA talked about integration for years years and we do a lot around demand response, but we also know that there's energy efficiency stuff out there and we kind of need to work in cooperation with it. PLMA doesn't own the integration idea. There are many partner organizations that have a role in it too.

This particular panel is put together as part of a partnership with AESP. They have a role in integration and integrated demand side management, DERs. And we have a role in it. This is the second joint presentation that we've done at conferences in addition to a couple of webinars. And people within PLMA have said, "We need to talk more about this". As a result, we have put together five fabulous experts to talk about integration. Whether you call it IDSM or IDER, so let's go.

I grew up in Montana, annd my big brother was a car guy, which meant I got to spend my time working on his vehicles. So let's talk engines! This is a single-cylinder engine, and single-cylinder engines have been the workhorse for the agricultural community. Some of the original tractors were single-cylinder engine tractors, great workhorse. They do a lot of really good stuff all by themselves. Take energy efficiency, demand response, distributed resources. Each by themselves do some really amazing things for our grid.

But... this is a five-cylinder engine. A five-cylinder rotary engine to be precise. And when you integrate those five cylinders together, they can do something really amazing. They can fly! That's the value that we get when we're able to integrate all of these different things that we're doing. The whole really is greater than the sum of the parts. So, with that, I would like to have our panelists introduce themselves, perhaps tell you interesting things about themselves and maybe something interesting they picked up along the way for the last few days. Let's start here, introduce yourselves and we'll get going with the conversation.

Paul Wassink: Hi, I'm Paul Wassink. I'm the program manager at National Grid for demand response. Something I learned that really blew me away was on the first day, a guy was talking to me about reusing EV batteries. And he had this graph, I think it was from like McKinsey or something on the worldwide demand for batteries for the next 40 years. And then he charted the worldwide supply for 2nd life EV batteries and they were like the same. It's like, wow, can't we just reuse EV batteries for our grid needs? So that's what I'm going to try to do when I get home.

Mathew Sachs: I've spent the better part of the last 12 years investing in and building businesses in the new energy space. I recently joined CPower and lead our strategy and business development efforts. One key reason I joined is that I really do think we're well positioned to help the people in this room move the future forward. Before CPower I was at National Grid, but on the unregulated side. However, I spent my fair share of time in utility board rooms and PSC meetings, so suspect I can relate to at least some of the challenges folks in this room are working through.

As far as what's interesting, this is my first PLMA and I'm really encouraged at the innovative attitude and enthusiasm to find a better way that came across in the talks and presentations here.

Greg Wikler: Greg Wikler here. I'm actually not with AESP as a staff person, but I represent AESP on the board, Association of Energy Services Professionals. But in my day job, I am the executive director of the California Efficiency and Demand Management Council (CEDMC). Just pointing those two words out because of course that suggests integration. I've been in the industry for a few years and have been focused on these issues. It's certainly a passion of mine, and very excited to be here today to talk about it. And my takeaway, actually a lot of takeaways, but the one that I shared with Joel Gilbert, just right after lunch.. I was struck by that discussion about pricing and the challenge that we all face with regards to integration and that we have to get it right.

And the reality is customers are doing it, that they're kind of ahead of us, and I don't think we have a lot of time to figure it out. And that was kind of my aha was: This stuff is happening and we're kind of catching up. So, I'm looking forward to having good discussions and, with regard to the partnership that Jenny mentioned, we have been working together both organizations, AESP and PLMA for a few years and have put on some really amazing webinars. Amazing in the sense that we're getting a lot of folks interested to talk about the issues and doing some collaboration at our respective conferences. So, looking forward to continuing the dialogue after today as well.

Brett Feldman: I'm Brett Feldman with Navigant Rresearch. Something that I learned that I'm really going to build off with my comments here is, I think throughout the conference I've heard people going back to the customer, building on what Greg said too. I think in the first panel yesterday, one of them said the technology's there. It's not really about the technology, it's about getting the customers engaged. I know Joel was hammering that away too. And I think on the panel with Con Ed and Eversource, someone else said, you know, you've got to think about it from the customer perspective. So, I think up here I'm not a vendor or a service provider or utilities. I'm going to really try to keep pushing the customer perspective.

Justin Chamberlain: I'm Justin Chamberlain at CPS Energy. I help manage our energy efficiency and demand response programs. So, we have a portfolio of programs that we offer customers and we have a great strong team helping us execute those programs. As far as takeaways from the conference, something that I guess is encouraging for me, were all the presentations about EV programs and engaging our customers in EVs. I'm happy to hear we're not alone in the work or the pressure, and I look forward to seeing in these future PLMAs the progress that's being made.

Olivia Patterson: I'm Olivia Patterson with Opinion Dynamics. I'm really happy to be working with Jenny to do this closing session. We have a great set of panelists, as she mentioned. The first question is "What does integration mean to you?".

Wassink: I thought at National Grid that we had this down because, when we started doing demand response about five years ago, it was brought in as another energy efficiency measure. So, I had heard stories from like California and other places where demand response and energy efficiency were separate, and I thought "Well we don't have to worry about that". We're already integrated, we're using the same sales force, the same marketplace, adding incentives at time of purchase. But recently my complacency was shook-up a bit. We did a nonwires alternative (NWA) pilot, and we've done non-wires before. Usually it's done by the grid side of National Grid, so not the customer side. And we've done things like up in Buffalo we had that marketplace thing, which was very difficult to get customers and vendors engaged in something somewhat complicated in a very small area.

And we've done the RFP routes where we go out and we just say "Hey, give us your solutions". And the solutions always come back more expensive than the grid alternative because it's such a small area, it's really hard to afford the overhead of a DR program in a place that has 5,000 customers. So recently we did another NWA pilot where we just said, "Hey, in this area we're just going to increase the DR and EE incentives by twice and see what happens". A week later we had to shut down the program because there was no actual grid need, but we way over sold the capacity, our sales guys were way too successful at that. So, I think that's what integration means to me. It's not only EE and DR, but also trying to get all the pieces of the utility working together, both on the customer side and on the wires side to use all our resources together.

Patterson: Yeah. It's more than just EE plus DR, it's bigger than that. Mathew, you come from both a utility and a vendor perspective. Can you speak to this issue as well?

Sachs: I think that's a great example to start with, Paul. To me it's along the same line, but perhaps a slightly different angle. Integration of DR is the orchestration of a series of loads and DG assets that are behind a single meter to produce the optimal value proposition. That value proposition extends to both the grid side, across different programs, and the customer side. This is really an evolution we've been going through for some time. For example, we've been putting generators in the market alongside curtailed load and that's nothing new.

More recently, that has extended to a whole assortment of new DG style assets. things like batteries, solar, even fuel cells. One great example is what we've been doing with microgrids. One customer we have is Scale Microgrid Solutions. They developed a project with a vertical farm who wanted greater resiliency and perhaps some of the bill-side savings that are possible with the technologies Scale offers. Scale developed a microgrid complete with a genset, solar and battery. We [CPower] were able to enroll this project in a series of programs and optimize the microgrid assets across different value streams. I think this is really a bit of canary in the coal mine of where we're headed in that there's going to be an increasing number of customers that elect to put more devices behind the meter and that we can use these devices to unlock new value streams.

Patterson: Brett, as a research director you probably get to see this from multiple different perspectives, whether it's technological or organizational or financial. Do you want to speak a little bit to what you're seeing in terms of integration?

Feldman: If it was just about any rate and the technology, that would be easy, right? That's probably the smallest barrier that we have, the technology is there for the most part. You'd have to do some software integration and make sure you have systems that are interoperable. But the things that I think about are organizational, as we talked about in the beginning with the silos, right? And we've heard throughout the conference.

The DR group has to talk with operations and customer group and metering and all these different groups. So, it's integration on the utility side organizationally. And then on the financing side also you have a power purchase agreement for solar, you've got a performance contract for energy efficiency, you get paid for DR, and how can someone package those different financing perspectives together into something viable for the customer. And then finally, integrating the customer offering. You can't just throw a restaurant menu of great technologies at a customer and say "Here, you choose", they're not going to know what to do. So, you really have to integrate the solution to meet a specific customer need. And I think that's where it all comes together.

Patterson: We always hear about cylinders of excellence. Which is the biggest barrier to integration: regulatory, technical, utility culture, utility business models, customer/market design, or something else?

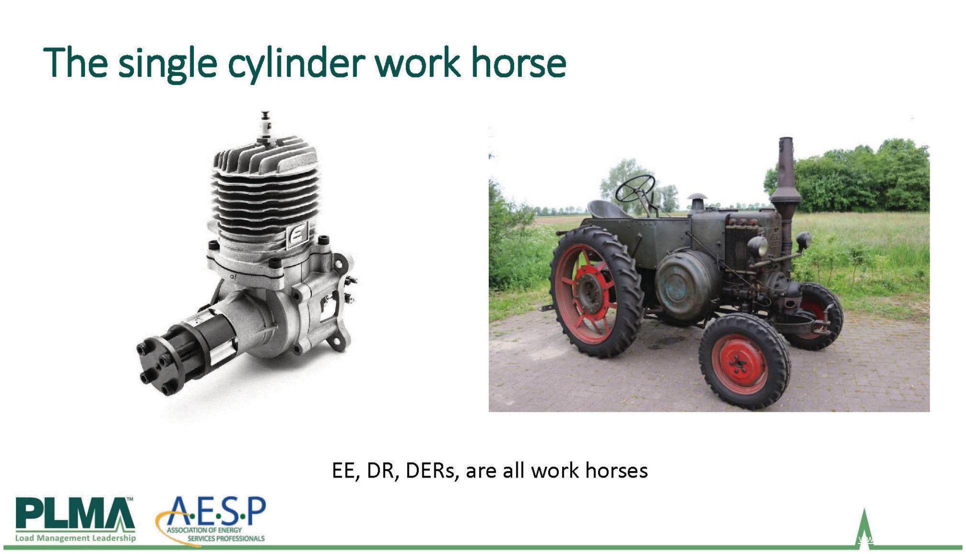
Wikler: First on my list was culture of the utility. Utility silos. And I think a lot of the challenge is perception of "this stuff just doesn't work" from different groups within the utilities. So, we as demandside practitioners always have that challenge to overcome. Regulatory silos are just there, we have to figure out ways to overcome them because those silos are there in terms of funding buckets and whatnot. But program designs are also problematic because we'd taken cookie cutter approaches that we developed 20, 30 years ago and we're trying to force fit those into today's sort of situation and customers don't really see it that way. And then finally, customer awareness is another barrier I think in terms of their knowledge and awareness of what DERs can do for them.

Patterson: We talked a little bit about what the barriers are, and I wanted to ask the panelists since we want to think about opportunities, not just challenges, how have you seen barriers addressed without true integration. So, if we're in a world without the vision of truly integrated programs. What are some examples you've seen, how we've been able to address those barriers?

Sachs: I think the utility business model is one of the biggest barriers. The reason behind that is the one thing that I think eludes us is quantifying the value of reduced loads and distributed assets to a distribution network. And there is certainly local value there - Sometimes a lot, sometimes a little, perhaps maybe negative in some cases. Unfortunately, the fundamental model that utility businesses operate under does not typically compensate most utilities for pursuing non-wire solutions, other software based solutions, or anything that favors OPEX over CAPEX, that could begin to unlock this value.

There has been a few interesting early developments. The UK uses something called TOTEX that rewards and pays a return on both OPEX, and of course CAPEX. In New York, as well as some other regions, they've done some interesting things with, performance-based regulations that is starting to get traction; however, the programs are often not big enough to give the utility folks in this room the right business case to expand outside of learnings and make the case that these solutions are needed to prepare for the future. We all need to make money now. If I had another vote, I would likely pick market design. We certainly want pricing to be predictable.

To be clear, that doesn't mean prices should be fixed. It means that we all need to understand what factors drive pricing. So, we can make an educated guess on what the future might look like. One last point is how to get information out to the market. I think this is a real opportunity for utilities to build platforms that communicate value, at more granular levels, and allow DERs to



SLIDE 22 View Slide at: https://bit.ly/2Riu2kv

monetizes this local value. This would really start to build the future. I have been party to a lot of chats like this one and this is one of the things that really encouraged me, so let's see how this evolves in the next year.

Patterson: Greg, you have some experience in the California environment in terms of how barriers have been able to be reduced without potentially the reduction in regulatory silos.

Wikler: Yeah, it's interesting that you ask a Californian something about success. It's kind of ironic these days. But anyway, we're struggling on a number of issues in our space. But one thing that we did look at a few years ago, I was involved in when I was in Navigant, we did a pilot with the utilities, it's called market-based incentives. And it was really more designed on the energy efficiency side. But the idea was... it had to do with localized nonwires alternative types of projects where, setting the incentive of the traditional approach is just a kind of... And Paul, I think you alluded to it at National Grid is that we've just double it and see what happens, you know, whereas in the market NBI example, we looked at, what are the specific business needs that are localized?

And then we've aligned that need with how we set the incentives. So, incentives would vary depending on the local condition. And the way that the pilot is now evolving is that there's incentives that are set really more at a local level, and customers can be, perhaps more responsive, maybe induced by a sort of a mindset of being a responsible participant in terms of what they would need to compensate for their participation. That's in the context of the local situation.

Patterson: Justin, I wanted to get your take on what are some strategies to reduce those barriers and be successful?

Chamberlain: Well, things that we're working on, and it's a slow evolution in this, of how do we change our business models. So, in our area of the company, we've focused on DR for multiple years and energy efficiency has just become part of our team and we thought, "Hey, we can change things up" and these things take some time to be able to change cultures. Also, when you have people who are supporting them, not just vendor supporting them, but you have trade allies supporting these things, take some time to evolve. And so, we're trying to work on some small things to be able to get them out and change the way we're offering these programs. And so, ways we're seeing some integration is through bundling of our offerings to the customers. Trying to make it simple. We're one utility, we shouldn't have to send multiple vendors out to your house to be able to serve you or support you.

And so in trying to make it a one simple trip, like residential customer, if we're going to go out there, give you an assessment, change some light bulbs. Oh, we're going to put a thermostat in at the same time. And so, we're trying to do both. One trip–make it easy. We have programs where we're working with our commercial customers, where we are going in there and helping them tune up their buildings. And so, we're opening up their building management system, incentivizing vendors to go in there and make sure everything's working correctly. Well, while you've got the system open, while you're working on it, put in some DR controls, help them be flexible, help them be responsive to our DR commands. And so, it's some little things that we're doing to be able to bundle those, to be able to help customers when they're already interacting with us. Don't make them come interact with us again another times, just take care of everything that we can at one time. And so that's helping us slowly start bringing our programs together.

Patterson: What are some of the aspects associated with policy objectives that are constraining your environment?

Wassink: A recent example would be in Massachusetts where they're actually three stackable yet competing incentives for battery storage, which I mean, everybody's I think rowing the right direction, ish. I mean, more incentives should help, right? But each one has its own rules, its own caps, its own limitations, and it's hard to educate the vendors and the customers about three various programs. They're not all utility programs. In Rhode Island, we've actually been more successful because there's just one incentive, just slightly bigger. I think policy helps and sometimes it's not always in our control. If there's a state policy and there's a state incentive, we need to adapt to that. However, if we can work with state policy makers before they decide to launch a new incentive and give them options to achieve their objects without so much customer confusion, everyone will come out ahead.

Patterson: Brett, do you have any thoughts on the policy constraints and what you've seen in terms of the research you've done?

Feldman: We have all the typical ones, but one new one that I'll just focus on is the push for electrification, right? I think that changes the paradigm a lot. You're not always looking to reduce load, reduce KWH, it's being more strategic about it. So, it's not as simple as just saying we're going to cut here. It's about when it's used, what the emissions profile is, what the cost is. So, I think that's something that we're all going to have to deal with from a regulatory perspective. And how do you figure out the value of these things and just bringing it back to the customer side, I think there's a mirror image on the customer. Some customers are driven by cost concerns, some are driven by sustainability goals. Some are driven by comfort needs. So, it's the same thing on the customer side. You always have to think about what whether it's regulatory or customer, what goal you're trying to meet because there's a different solution and a different way to frame it. Whoever you're trying to address.

Patterson: Greg, there might be some changes in the cost-effectiveness landscape. Do you want to speak a little bit to that?

Wikler: I'd say that might be ambitious to say that changes are coming right away. But the idea is we need to be rethinking cost effectiveness. We've force fit an old model of total resource costs using standard practice methods to basically try to assess across the spectrum of distributed energy resources and it doesn't work for a variety of reasons. There is a movement afloat to really update the National Standard Practice Manual. It's an NSPM, for short, effort that E4theFuture has been launching and getting really a lot of folks involved in terms of trying to enhance the cost effectiveness methodology.

That's one effort that will be helpful for how to assess the economic viability of distributed energy resources in integrating those different resources going forward. But it's going to take some time and a lot of work has to be done.

Patterson: If you could ask your regulatory body PUC or anybody for just one thing to support integration, what would it be?

Wikler: Well in my state of California, we have this concept called incrementality, and maybe some of you have heard of it, but it's this fear of not wanting to use one resource to cover another resource. It's sort of related to these silo issues. So, if there was one thing that I would like to ask my regulators, and I'm actually asking them, is to eliminate the concept of incrementality because I do think it's a huge barrier for participation.

Patterson: Brett, if you were going to work with your clients in terms of something that they would reduce from a regulatory perspective, what would it be?

Feldman: I'd focused on the funding and again, you hear silos over and over. But it's hard if you have energy efficiency budget here, DR budget here, storage budget here, right? I mean ideally there'd be some way to mix them together and obviously there's concern about that and people fudging it and playing with it. But in the grand scheme, if there was a way to have the funding more fungible between programs and being able to show the benefits as well between programs that would be the place I would focus on.

Patterson: How about you Justin, as the largest municipally owned utility?

Chamberlain: I have to brag for a second that our regulatory set up for our DSM programs is actually one of the best. They are supportive of our programs. They allow us to measure it at the portfolio level and not on the program level. And so that gives us an opportunity to be able to try new innovative programs along with the tried and true programs. It helps us to be able to serve a have a large LMI (low to moderate income) underserved population. It allows us to balance weatherization programs. Actually, our weatherization budget is larger than our DR budget, but the cost effectiveness of our DR budget helps cover the loss that we may receive on that investment. And so, we have a really good setup. And so, I think what I would ask is that, please keep this flexibility to be able to serve all of our customers and be able to try out new programs.

SLIDE 23 View Slide at: https://bit.ly/2RIR2z9

We've had some programs that didn't work out so well, but it's given us the chance to try it out and retry and try to find some pathways to success. And also, to keep it as a single goal, right? Our single goal is KW, all right, it's a KW reduction and so we know what we're focused on and we know how to align all of our programs, all of our cost savings with that single goal.

Patterson: What if you were told that it had to be KW and KWH?

Chamberlain: It would change up the type of programs that we offer. EE would find a little bit more value in our stack, right now we get a lot of value out of our DR programs.

We have things like outdoor lighting at night. That would find a little bit more value and we'd be able to put a little bit more money behind these programs. It's the challenge on our side with KW and KWH is being able to measure and bring the two programs together and so it would encourage us to explore that more because now we don't have to go in and understand those baselines and how these programs integrate and work together.

Patterson: Matthew, I wanted to ask you from a vendor perspective, what would you ask the regulatory community to support your efforts?

Sachs: If I were to look for another ask of regulators, it really would be a better road toward innovation. It's a fundamental structural problem. Regulators sometimes act as an innovation capacitor. Rightfully so. It's not their job to go out and figure out what the next widget is, it's their job to protect the customer. But there is customer value, perhaps longer-term, in innovation. I think we really need a new framework that could help utilities balance short-term vs long-term value. This is similar to what was described for CPS, to invest a little bit more in the future, to allow for future cost savings or customer benefits. I'm convinced that innovation is going into regulators and one day, just like a capacitor, it's going to just discharge all at once. I'm a little scared it'll discharge too quickly and cause too much disruption that cannot be controlled and could result in a sub-optimal outcome for everyone. I would ask regulators to define frameworks to allow greater innovation at utilities and ensure it drains out at the right pace.

Patterson: So now for something slightly different, less on the regulatory side, the question is, is there a difference between behind the meter resources or front of the meter resources, or should it matter if the customer owns the resource or not? And I'll start with Paul.

Wassink: We believe in the all-of-the-above approach. So, in front of the meter and behind the meter are both great and valid. Might be a little bit self-serving because I work on a behind the meter customer-owned program. But I think behind the meter should lead, because there's a potential financial conflict of interests to front of the meter grid owned assets. Regulators know that, it's not a secret. So, they have to be very careful when they approve those projects. And very careful means taking a very long time. If we have a program where customers own the assets at the same time and yet they're lagging in a certain area where we could do an NWA or another project, then we could say "Hey, we tried the customer owned approach and it's not quite meeting the whole need." It makes it a lot easier for those regulatory bodies to approve grid-owned assets.

Patterson: Justin, do you have any thoughts on the question, in front of the meter or behind the meter?

Chamberlain: We have to build our business model to be able to support that growth. We want to see it happen, but we have to make sure that we're covering all of our customers too with the investments that we're making in their infrastructure. On the other side though, we're also doing community solar projects, allowing customers who aren't able to have it at their homes to be able to buy from us where they're getting the parity of the lower price. We're able to build these projects much larger and at a lower price point where they can get involved and we can build that business model to be able to support them to be able to participate.

Sachs: I somewhat agree with everyone, but particularly those last words in the sense that if solutions have customer value and a customer already finds value in the solution, then that customer value will help subsidize the generation of value to the grid. Conversely the grid value will also help subsidize the cost of the customer solution. Not every asset has customer and grid value. Assets that only have grid value will likely be more economic to deploy in front-of-the-meter.

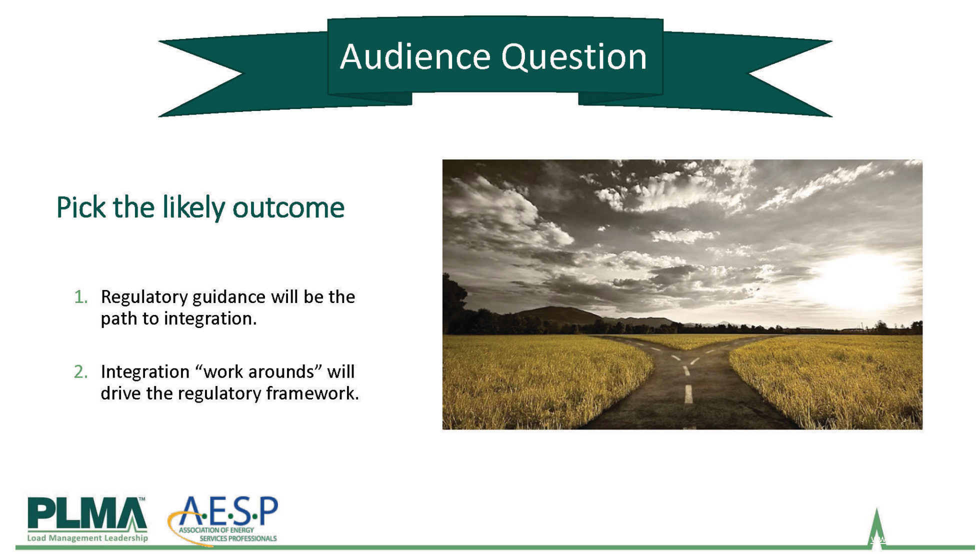
Patterson: Time for some audience participation.

Roehm: All right, so which cylinder... this is a little controversial actually. Which cylinder do you see as the most important of the following: energy efficiency, demand response, distributed generation, micro grid, storage and EV, or no single one is most important. n.

Audience 3: I think storage and EVs because, on the horizon, that is going to be probably one of our largest problematic areas, and our overall distribution grids, and if we don't address it now and get the infrastructure in and the ability to help control how that works inside of our grid, we're going to have major issues over the next 10, 12 years.

Justin Felt: Justin Felt, BGE... well, it kind of comes to the last comment, it was storage and EVs. How do we integrate, how do we deal with all the DRs that are coming online? Storage can be part of the solution, so can EVs. They're both a problem and a solution. But demand response is always sort of the interesting question. I think, all else being equal, it would always be one of the most cost effective solutions. The question is, can you get customers on board? But as we think about technology, evolution, connected devices, that load is going to become much, much more variable. A much more... something that the local distribution utility can affect and manage. So, I see it as an area where there can be a lot of dynamic things happening in the coming years.

Joel Gilbert: I'd like the panel to react to this: I think we're trying to solve the problem the wrong way. I think the last bit of wire to the house should be DC from the last part of the distribution circuits. And we should be solving the storage problem with batteries at that point. And that the house should be DC because everything



SLIDE 24 View Slide at: https://bit.ly/37xzQfq

that's high tech in the house is now DC, solar panels on the roof, all the lighting systems are DC. The only thing left is a couple of motors. And if we put them at DC, we'd have variable speed, which would really be very nice. Why not go to the endpoint and prove that, rather than pick up these parts, which are so hard to do. Because I will tell you, if you had a DC community, it would sell out in a heartbeat.

Wikler: So, Joel, I'm not going to argue with you, because I agree. But I still have to go back to all these items that are on the list and think about, okay... so all these things are important in your context. And so, to Mark's point about EVs and storage. So, getting to that point of what we need to do first and foremost, I harken back to my sort of original days. Some of us have been practitioners of energy efficiency for many, many years. Efficiency first, it's the no brainer, it's the setup for basically an efficient deployment of these other resources. Especially if you're thinking about electrification efforts with EVs, if we're changing out, gas end uses, space heating, water, heating, whatnot, your densities have to be at sort of at the lowest point possible to accommodate these added loads.

So I put efficiency sort of at a high level, not saying that's the only one, but it's a high. And then to the point about demand response, it's kind of my observation over the last several years that we started out in a good place as far as using DR to help mitigate peak load issues. And the way the role that DR has evolved into, especially with connecting with advanced technologies and whatnot is that, demand response is increasingly becoming more of a facilitator of a lot of these other distributed energy resources. So, it's not that the DR programs in and of themselves are necessarily sustainable in the long run, but demand response is going to increasingly be an important element of integration of the other resources.

Audience 5: I thought distributed generation was the most important. But why I did that is also a bit to raise awareness to, maybe a European perspective on the issue where I think the demand response community is much closer to the renewables community also. And the volatility of the renewables is basically responded to by storage and demand response. And I was surprised when coming here that this is not really a big discussion. So that also just a thought and the reason why I had said distributed generation, because distributed generation is of course not only diesel gensets but also renewables.

Audience 6: This may seem like a really simple point coming from a really narrow perspective, but from a utility or regulator standpoint, it seems like all of these have different levels of disruption to the energy services industry or the energy market or the technology markets, but they all relate to customers. And so from a service standpoint, we have to pay as much attention to the customer who has a particular interest in this level of deployment in their home, in their search, in their situation, circumstance as... and we have to pay as much attention to them as we do the customer who wants a large microgrid to be able to island and serve hospital customers during a weather event.

So it's almost a false leveling that takes place in that case because we have to pay as much attention to all of these different programs and opportunities at that level, as if you have a responsibility to serve. And so that was really kind of what drove my answer with no single one is more important. But they certainly all do have very different scales of opportunity or reaction requirement.

Audience 7: Here's maybe a different angle on this question. What problem are we trying to solve here? And I would propose, maybe it's something for the panel, that maybe the... if you look at what we have today, it works pretty effing good. Really. When you get right down to it, I mean the rates are basically low. The reliability's pretty good, stuff like that. So, I would say, well maybe what we're trying to solve here is how do we make it better? What are we trying to improve? And I would suggest maybe that's reliability, and we want to keep the cost of renewable integration low. So, I would say in that sense, if you look at these different technologies to your integration point that it's maybe how do you orchestrate these things such that you can achieve those.

Patterson: Yeah, how to solve for the customer as well as for the grid. I wonder if any of the panelists want to chime in here for, I'm loving the audience participation, but you probably have some thoughts on the matter.

Sachs: I think that's s a pivotal point. Actually, both the prior two points. For one, it's not really our choice. Customers are going to do what customers want to do. Can we find new values in what customers choose to do? And two, what problems are we trying to solve. If we were to look at these two points on a region-by-region basis we might get very different answers and encounter different problems that require different tools to solve them.

The focus is about bringing down costs across solutions, but you're right, it's about making it better, not making it work. The technology is there. Basically, in any one region one technology might be dominant, but across the country you need a lot of tools.

Feldman: Maybe just one other thing that we haven't talked about here is rates. We've had some panels here on rates and that can affect all these different things. And maybe you don't see it as a resource on its own, but it's another lever that you can use to impact all these different things.

Sachs: I didn't think of that. But time of use could be great, it could be a great enabler for many of these solutions.

Audience 8: I think to answer a little bit of his question, I don't know if this is simple, maybe I'm oversimplifying, but I think the problem, and it's also the opportunity, it's the whole push for clean energy, right? So, it's the new sources of energy at the generation point. So, it's always been iron on the ground, it's been coal, it's been natural gas and you're right, it works great. The grid just kind of delivers it, right? But all of these things up here, we need these now to kind of work with the new forms of generation. I mean that's what it comes down to.

Audience 9: One of the things with storage and EVs is that as a utility we're behind the customers now. They're adopting faster than we can keep up with them. And that's an area that I think we've got to make sure that we're in step, or ahead of step with them as those items come on.

Patterson: So, I wanted to ask the panelists, in five years from now, what do you think the energy landscape's going to look like?

Wassink: I think the future is already here. I think it's just not well distributed yet. So, I think I do a few things great in my service area, but I learned a lot of the things here this week that I'm not doing. Gas demand response, a better job with batteries, customer feedback, getting an EV program. So, I think five years from now is going to look a lot like it does now. It's just, probably we'll all be doing all these things across the board.

Sachs: Not necessarily looking from a utilities' perspective, but rather from an energy service company perspective, I think the future will be governed by three tenants. The first one, go figure, is solve the customer's problems. You could probably apply that to any business across the history of businesses. But what I mean by that is, right now we often approach customers, and you said this earlier as well Justin, with a technology. We're trying to sell a technology and I think the approach to customers must change to, "what is your problem?" And all the technologies being sold, including solar, energy storage, DR, anything else being sold, are all tools in the toolkit. In other words, we need to change the conversation and seek to solve customer's problems as opposed to selling technologies.

We're likely to hear from the customer something like: I want cheaper energy, I want it to be reliable, I want it to help me progress towards my sustainability goals and I want everything simply. I don't want to worry. That brings me to the second tenant, which is simplify the solution. Customers don't typically want to understand how a battery works, what's the technology risk, or the future pricing curve on ISO wholesale prices. That's not what most of these companies do – nor should it be. So, we have to figure out how to make it simpler. As-a-service type business model, brings the value to their bottom line. How much are they going to make or how much are they going to save.

The third tenant is, I think very relevant to this group, is to aggregate and optimize and bring a bunch of distributed loads and assets together to become a virtual power plant. This will allow the value on the grid to subsidize the customer and vice versa. I think this is where we're going and in five years, I hope, when we meet at future PLMA events we could really talk to success. I know I voted for (choice) two when the utility question was proposed before (or the regulator question?) but I do think it's going to start at utilities. It has to. Utilities are the only ones in a position to really make that happen quickly. So that's my future.

Wikler: What's just been on my mind lately is, given where I live and what we're dealing with, we're dealing with an existential crisis with climate change. I think some parts of the country are dealing with it more severely than other parts. But I'd say that, obviously where I see the DERs going has a lot to do with where utilities and customers are feeling the need to become more resilient. That literally the current situation is not sustainable, especially in California with wildfires. So, thinking about, how do we rebuild a grid that is more resilient, has to involve distributed energy resources and we're seeing it play out.

So, I agree with you, Paul, that we see it today. We don't see enough of it, but we see it, we see the models. We see what Joel's describing as far as the idea of actually being able to imagine different delivery methods or thinking about direct current versus alternating current at the household level. I think we're finding that those are the solution paths that we're going to see a lot more of in five years. And so I'm optimistic, I'm glass half full perspective, and I think we'll probably see a lot more distributed energy resources, micro grids, much more of that happening around the country and hopefully leading us to more resiliency than we're currently seeing today in some parts of the country.

Feldman: I guess maybe I'll do the other half of the glass from Greg. I do forecasts for my living. You know, we look out 10 years and some days I wake up and 10 years seems like it's way, way out in the distance and the next day I'll wake up and 10 years, like "Wow, that's going to happen tomorrow". It's really interesting to think 10 years out. So, five years is even less. And in this industry not all that much happens in five years typically, right? New York REV started over five years ago. How far has that gotten? Still a lot of pilots I'm sure Greg can talk about in California how long things take and go back and forth. I participated in the Massachusetts Grid Mod Proceeding that started in 2012, that's still going on.

So I guess looking historically I might be a little skeptical, but maybe there is a chance that we can increase that pace going forward and, not to steal Justin's thunder if he has some, I think the munis and the co-ops do have more opportunity to move quicker on these types of things. So, I would see them leading and then to Mark's point, it will be more of the customer adoption rates of electric vehicles and thermostats and all these other things and needing things for resiliency that I think will be the driver. So, I think it'd be more reactive on the part of the industry as opposed to being more proactive within five years. If you want to look further out, maybe that'll change. But to me five years is still not that long.

Patterson: Brett, can I ask 15 years, how would your answer change?

Feldman: I think 15 is more reasonable to see longer term change. And I think it also goes to the culture and the professionals that are here. I think we've seen more younger people getting into the industry and utilities and other companies are hiring people who are looking at the world differently than maybe the old guard did. So, I think it does take some of that kind of generational turnover to really build from the ground up to get that change.

Chamberlain: So good news is you didn't steal my thunder. I think about the last five years was my first actual PLMA conference and I'm actually doing some of the same exact things I did five years ago. Not a lot has changed. We've got a lot of opportunity as munis, but the simple programs are what make our programs cost effective. And so, when we moved to that next cost per KW, it's difficult. Because you're having to sacrifice what you're already doing. And so, what I see over the next years from us is the idea that these traditional programs, these energy efficiency programs will slowly evolve.

We have 34 programs to offer customers, way too many–hard to manage. I think it will be a lot simpler in the future where we'll be working with customers to try and to manage the whole load programs. Commercial and residential customers will be different, but we'll have to find ways to be able to serve them holistically than just these simple measures.

Presentation slides available at https://bit.ly/2TLATVg