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BEFORE THE

CALIFORNIA ENERGY COMMISSION

In the matter of,	)	
	)	Docket No. 17-IEPR-12
	)	
2017 Integrated Energy Policy	)	
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IEPR COMMISSIONER WORKSHOP ON

DEMAND RESPONSE

CALIFORNIA ENERGY COMMISSION

FIRST FLOOR, ART ROSENFELD HEARING ROOM

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

TUESDAY, AUGUST 8, 2017

10:00 A.M.

Reported By:
Gigi Lastra

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Andrew McAllister, California Energy Commission

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Karen Douglas, California Energy Commission

Joint Agency Participants

Martha Guzman Aceves, Commissioner, California Public Utilities Commission

Keith Casey, California Independent System Operator

CEC Staff Present

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Presenters Present

Bryan Early, California Energy Commission

Bruce Kaneshiro, California Public Utilities Commission

Jill Powers, California Independent System Operator

Mary Anne Piette, Lawrence Berkeley National Laboratory

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Gabriel Taylor, California Energy Commission

APPEARANCES

Panel 1 Members Present

David Hungerford, Moderator, California Energy Commission

Mona Tierney-Lloyd, EnerNOC

Jamie Fine, Environmental Defense Fund

Barbara Barkovich, California Large Energy Consumers Association

Erica Keating, Southern California Edison

Panel 2 Members Present

Gabriel Taylor, Moderator, California Energy Commission

Aaron Panzer, Ecova

Susan Kennedy, Advanced Microgrid Solutions

John Anderson, OhmConnect

Matt Eggers, Yardi

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Panel 3 Members Present

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P R O C E E D I N G S

AUGUST 8, 2017 10:04 A.M.

MS. RAITT: Okay, we have a very full day so we'll go ahead and try to get started here.

(Pause)

CHAIR WEISENMILLER: Okay, let's start this. We've got a lot of ground to cover today so --

MS. RAITT: Okay, good morning.

CHAIR WEISENMILLER: Yeah, make the announcements.

MS. RAITT: I'm going to go ahead and get started. So, welcome to today's IEPR Workshop on Demand Response. We've got a great crowd. We have a very full day.

I'll go over the housekeeping items. If folks could go ahead and take their seats, please?

Okay, so we'll go ahead. So, I just wanted everyone to know that we are being broadcast through our WebEx recording system and so everything is being recorded. And we will have an audio recording posted on our website in about a week and a written transcript in about a month.

We do have a very full agenda, so I would like to ask our speakers to please stay within your allotted times, and I really appreciate you being here today.

At the end of the day we will have an opportunity for public comment. We'll be limiting those to three minutes per person. You can go ahead and fill out a blue card and let us know that you'd like to make comments.

For folks on WebEx, go ahead and use your chat function to let us know that at the end of the day you'd like to make a comment.

And we'll open the phone lines at the very end.

Written comments are welcome. They're due August 22nd. And the notice provides all the information for submitting comments.

And with that, I'll turn it over to the Chair. Thanks.

CHAIR WEISENMILLER: Good morning. I want to thank everyone for being here, looking forward to a productive day.

This is sort of a workshop that's been in a series of workshops. We had a general staff workshop, back in June that looked at the roadmaps we've put together, the three agencies, on demand response, storage, vehicle-to-grid. And some of those are pretty old, frankly. So, you know, that was one of the things that came out of it and it was time to do a refresh.

And we followed up the staff workshop more at a committee level, again a high level, and now we want to drill down on demand response and see if we can make some progress on that.

I wanted to thank Commissioner McAllister for helping focus -- well, A, for volunteering to help focus this better and, again, get into this refresh mode for this particular roadmap. It's very important the three agencies work together on this and that we build off of the prior roadmap for going forward in the future.

Actually, I was going to let Andrew speak and then go to you two.

COMMISSIONER MCALLISTER: All right, thanks, Chair Weisenmiller. So, I'm super excited about today and I want to just thank everybody for coming, and really looking forward to a productive day.

This is going to be -- from my perspective, this is a very -- today is very substantive, but even today will only scratch the surface in terms of really getting down to practical solutions about to organize the conversation and with the end goal of getting markets to sort of wake up the potential that's out for demand response. Because I think, you know, I feel on the one hand I'm super optimistic about all the technology and how we can apply it, and there's some beautiful business models out there that are kind of evolving. And there's a stage that's at least partially set, so I'm super optimistic in that way.

But I also kind of feel like a schoolmarm, kind of continually, every couple of years kind of cracking the whip a little bit and saying, hey, people come on, you've got to pay attention. You know, do your homework, eat your vegetables because demand response is the right thing to do, okay. So, there are sort of two aspects of this.

We've funded a lot of work over the years at the Energy Commission to develop automated demand response, the protocols are out there. I'm seeing David Hungerford. I see Laurie tenHope over there. And we have a lot invested in this over the years. And now those are foundational tools to enable this practice to happen.

Sort of most proximately and urgently, I have this very strong sense that if we don't succeed in enabling this kind of a smart management through demand response, and by the way energy efficiency and demand response are increasingly one in the same. They leverage the same kinds of technologies and they're the same kind of just smart management. Investment in the right places strategically, we could do both at once and that's good practice. It's best for all of us, for the economy and for our State.

You know, this conversation had to move forward soon because we're at a critical juncture in the way we're organizing the operation of our grid. We're faced with long-term investments, with the retirement of our fossil fleet. We've got to reduce combustion. We've got to figure out new ways to do load management at the local, regional, and statewide levels. Demand response has to be a key piece of that or else we're going to over-invest in hardware. And that's, long-term, not going be the best for the State.

Now, we definitely need hardware. We need storage. We need lots of good stuff hanging from those wires. But smart management is cheap, and it's effective, and it's the right thing to do. So, we have to enable it to happen.

And I know I'm sounding a little moralist here, but I think ten years from now, if we haven't done this, we're going to have higher rates that we would have really needed to get the job done reliably and well.

So, demand response is just smart practice. And it's been under-utilized. We've tried a lot of ways. We're going to hear about some of the history. We've been at this for a while and I think there's some frustration that the system isn't producing the results that we'd hoped for that we set as our goals.

So, what are the barriers? What's happening today? What are the barriers and how are we going to solve them going forward? And, really, organize ourselves such that markets can deploy resources in the optimal way. You know, we have a grid that needs flexibility at all levels. And so, we have a lot of storage out there, already, in its various forms.

And one of the biggest forms is called buildings. We can use our buildings to manage the grid. They can provide tons of services. We don't necessarily need a lot of hardware to do that. But we need the correct rates, we need the right programs, we need an integrated suite of policies that work together well and seamlessly so that normal people can take these decisions.

We don't have that right now and we've got to figure out how to put that in place.

So, today is the first step towards that end. Not the first step. It's kind of one in an ongoing, but I see it as a very important step. And I'm looking forward to not only the discussion today, but the follow up afterwards, and really sort of marching down this road together, with all of you. So, thanks again for being here.

And I appreciate the ISO and the PUC for your participation. I think that's going to be critical going forward. You know, this is a joint discussion. This is not going to get solved by any one agency, but really together and in an organized and coordinated way.

So, with that I'll pass it off to Keith. Thanks for being here.

MR. CASEY: Yeah, thank you Chair Weisenmiller and Commissioners for the opportunity to be here and share the dais with you.

I, too, am looking forward to today's discussion and I would just echo Commissioner McAllister's comments about the critical role that demand response is going to need to play in de-carbonizing the grid. It's going to be absolutely essential as a flexible resource to help reduce reliance on, ultimately, the natural gas plants, which we're very dependent on now.

And I also agree that I think we're falling far short of where we need to be in terms of developing this vital resource. So, I look forward to hearing what the challenges and impediments are, and thoughts on how we can overcome them.

And I know, frankly, a lot of those challenges and impediments will rest with the ISO. Obviously, having these resources participate in our market, it comes down to what the market rules and operational requirements are. And I know there are concerns of things we need to address. And I want to assure you we take those concerns very seriously and we're committed to working with you in finding solutions.

But I do want to stress that it's important, as we look at these issues and try to find solutions, that we not lower the bar for DR where we actually undermine its value. We're not here to just develop demand response. That's not our objective.

Our objective is to develop demand response that is effective and highly valued to the grid, which means it has to be something we can call on every day. It has to be smart. It has to be automated. It has to be visible. We need to have the control it like we do other resources.

So, this is really about taking DR to the next level. And I look forward on how we can get there and what the ISO can do to help enable that.

So, again, thank you again and I look forward to the discussion.

CPUC COMMISSIONER GUZMAN ACEVES: Thank you, Keith. Well, as you guys probably are aware, because I see a lot of the same players, I am one of the assigned commissioners to the demand response proceeding at the

PUC, as well as working with my fellow commissioners on the resource adequacy proceeding.

And these are two of the areas where we've really seen a constant presentation of different barriers. And I really hope -- I know this is a long day, but I hope we can collectively try to gain some consensus on what may be some priorities that we, as Commissioners, and as the Board can work together to really get progress on this year.

And I recognize that's a really tough call upon all of you to try to reach some sort of consensus on where we should really focus on.

But in this time where we have a lot of customer choice, where we have really a fluctuating load, and where we want to see more competition of DR providers. These are all overlapping each other, but I certainly agree with what the Chairman and my fellow Commissioners, and Keith have all said about really being clear about what we need the products to provide so that we have a sustainable growth in the industry.

And also, my personal priority of trying to see DR really replace that one- and two-percent peaker dependency that we have. And we can only do that in a way where we're providing a really secure product.

So, I think it is also very exciting that we can be here collaborating to get to that point. So, I look forward to the discussion and learning from all of you on how we get there.

COMMISSIONER DOUGLAS: You know, I'll just briefly add on and support the comments that have been made by all of my colleagues here, and Commissioner McAllister in particular, who I know has spent many, many hours thinking about how to push DR in the State. As have, really, all of us and the PUC and the ISO, as well.

Some of the debate about DR really makes me think about a lot of the stories I've heard about the early days of energy efficiency in California, where there was this idea of how to meet our demands, and meet the needs of our system differently. And that idea had to be translated into actions, in some cases regulatory. You had to build a market. You had to think about how to fit energy efficiency into the way that we did business, and procured. And the business model of different market players.

And, you know, we have, over the time that just the Energy Commission's been in existence, for example, managed to create a really thriving energy efficiency ecosystem and market. And we've got very tangible and very strong successes in that area. And it's become bread and butter. It’s become a core part of how we do business and meet our needs in the State.

And I think that we will see the same kinds of successes in demand response.

I also agree with my colleagues that we need to see those changes. And sometimes it is easier to chase, you know, bright shiny objects and new technologies, and they’re tangible and you can see them.

But when we’re talking about getting to scale on meeting certain needs, cost effectively, you can’t beat approaches like energy efficiency and demand response. And, of course, that’s not the only tool and we need new technologies and we need to address across the board in a lot of different approaches.

But this one is and needs to be bread and butter, fundamental and just a core part of how we do business going forward.

So, I’m excited to be here. It’s great to have all of my colleagues here and I’m looking forward to the day.

COMMISSIONER HOCHSCHILD: Well, great. Thank you Mr. Chairman, and colleagues, and I particularly want to welcome Commissioner Guzman Aceves. It’s really great to have your many talents focused on this challenge.

So, I think we're in a world where there's things that get a lot of attention that are not that important, and then things that are really important that don't get much attention at all. And this is in the latter category

Really, demand response is just another name for cost reduction, another name for grid reliability, another name for renewables integration, and another name for pollution reduction.

And so, it has not progressed anywhere near to the level that we've wanted to see it, so I'm glad to help kick this off and look forward to the discussion.

MS. RAITT: Great. So, first we have Bryan Early, from the Energy Commission, to help set the stage for the policy level.

MR. EARLY: Hi, everyone. I'm Bryan Early. I work as Commissioner McAllister's Advisor.

I just wanted to provide a brief context. And I know we started a little bit late, so I'll be super, super quick.

I just want to remind folks, of course, that this is a part of the 2017 IEPR. And, of course, this won't be the first time that we have discussed demand response in the context of the IEPR. In particular, the 2013 IEPR did a deep dive on the subject and provided a series of recommendations and strategies to solve what it identified as demand response is falling short of its potential.

In a broad sense, the strategies that the 2013 IEPR offered included, first, enabling DR participation in CAISO markets, and developing and piloting market products. Second, resolving regulatory barriers. Third, continuing collaboration among the CEC, CPUC, CAISO and the Governor’s Office. And fourth, in a broad sense gaining customer acceptance of demand response.

We know significant progress has been made in several of these areas in the intervening years. For example, we’d like thank PUC, CAISO and CEC staff for working together on a demand responsiveness roadmap, which is currently being updated, as Commissioners heard about in the June 29th IEPR Workshop on Distributed Energy Resources.

So, in general, we’d like to spend the day hearing about the strategies laid out a few years ago have been implementing, describing remaining barriers, along with potential solutions. And, in particular, highlighting innovations in this realm. For example, for customer-centric DR automation and to summarize some of the updated thinking that occurred on the potential and role for demand response in our grid.

In terms of how we structure the day, we'll be hearing from the CAISO and PUC shortly about what has been accomplished so far and what work remains.

We'll also be hearing from Lawrence Berkeley National Lab about the potential for demand response going forward.

And we've convened a series of panel discussions on breaking down the current barriers for demand response, from the perspectives of different stakeholders. Including those who work in a space of unlocking the potential of buildings to provide grid services.

We'll also be hearing more about demand response and our building codes and have a discussion on the impact of rates.

And, as has been mentioned, the CEC has, of course, invested significantly in this arena, so we thought it wise to hear about the fruits of these investments in a panel, hearing from recipients of EPIC funds.

So, that's my summary of the day's objectives. And, again, I'd like to thank everyone for taking a day to discuss this really important resource.

COMMISSIONER MCALLISTER: I want to just start off, again, by thanking Bryan and for David Hungerford, for all of their work organizing today. They've been super proactive and, really, have probably talked with most of you in the room, and certainly all the panelists. So, I want to just thank them preemptively for a good day.

MS. RAITT: Okay, so our first speaker is Bruce Kaneshiro from the CPUC.

MR. KANESHIRO: All right, good morning Commissioners. It's my pleasure to be here. Thank you for the invitation to present on demand response.

Again, I'm Bruce Kaneshiro. I'm the Supervisor for the Demand Response Section in the Energy Division at the CPUC. And as Bryan has said, I'm going to be walking us through some of the policy accomplishments that have occurred since 2013, on demand response.

But before I do that, I thought it would be good to provide some background information on DR, where we are today with the resource.

So, if you will advance that slide there. So, this chart gives you an idea of how much DR we have in terms of megawatts, the load reduction that they provide when triggered.

As you can see from that top row, the amount of DR has been relatively stable, averaging about 2,200 megawatts, 2,000 megawatts each year. That's the utilities' portfolio.

What's recently occurred, in 2016, was the start of what's known as the DRAM, or the Demand Response Auction Mechanism. And that is through third-parties providing demand response. Although, third-parties actually provide DR, indeed, to the portfolio, as well. And I'll explain the distinction between that and DRAM a little bit later.

But this just gives you an idea of where we are in terms of total amount of DR that's out there with the California IOUs and third-parties.

About roughly half of the DR capacity that you see there comes from programs that are used for, I mean, what are known as emergency or reliability situations, where the grid is threatened, and they're called. I'm not sure, maybe once a year, sometimes not that often. But when they are called, they deliver quite a bit of reliable demand response in those situations.

The portfolio also includes what's known as time-differentiated rates, such as time-of-use rates, critical peak pricing. So, those megawatts that come from tariffs and rates, such as that, are part of the megawatts you see here.

We don't have any demand response that incents customers to increase their consumption of electricity to help with the duck curve. So, all the DR you see today, other than I believe a PG&E pilot, focuses on shed reduction during the peak hours. And these programs are triggered -- the DR programs are triggered a day ahead, the customers are given a day-ahead notification to reduce load the next day. The reliability programs are day of.

And then, lastly, 2019 is a big year for, I think, demand response in California. That's when I think most of know our time-of-use rates will be implemented to the residential class on a default basis. The utilities are right now doing pilots to test customer responsiveness to TOU rates.

And so, there's going to be a lot of interesting things happening with that in terms of load reduction that comes from TOU.

I believe Mary Ann's presentation might have some information on what the estimates are for TOU default in future years.

Okay, I'm going to move on to some PUC accomplishments, key things that have occurred since 2013.

Demand Response Potential Study, I'm skipping right over that because I know Mary Ann's going to talk about that in her presentation.

The second bullet point, adopted bifurcation. So, it’s a policy where we’ve essentially categorized demand response into two types of DR. And I’ll explain -- actually, I’ll explain each of these in more slides further on down.

So, the key idea here, though, is this implementation of integrating demand response into ISO markets, and there’s a deadline of 2018 for that.

Authorized the demand response option mechanism. Again, a pilot that’s meant to engage third-party DR providers.

We adopted a new goal for DR, and some new principles that happened last year.

And then, there’s a new issue that’s come up fairly recently, and it’s this whole issue about customer data, and the need for third-party providers to access that data quickly, but at the same time we need to protect customer privacy.

So, how do we do that? And so, there’s been some accomplishments there. And I’ll explain, again, these in detail a little bit later.

So, going to bifurcation, so we step back a second and think back to 2013. You know, the goal back then, amongst the CEC, the CAISO, the PUC was we need demand response to be integrated into ISO markets. Make it a visible resource that the ISO can see and it can be triggered based on bid prices, and so forth.

Up until that time demand response was essentially triggered by the IOUs, when they felt the need to. If there was a system emergency, the CAISO would make requests. But for the most part demand response was not very visible to the grid operator.

And so, the push at that time, in 2013, was to move the existing portfolio DR programs into the CAISO market. Make them bid resources, where they would be bid and dispatched by the ISO.

But before we could to that, we had to figure out, well, which of the programs are actually appropriate to be moved into the ISO market, as there were some programs that stakeholders were raising to our attention that were not appropriate to be considered wholesale resources bid into the ISO market.

So, what came out of that whole process is what is known as bifurcation, where we split the existing DR portfolio into two buckets of resources.

Supply resources, those are the ones that will be bid into the wholesale markets. This includes the emergency DR programs, a lot of price-responsive programs.

Then, there are what’s known as load-modifying resources. They're not integrated into the ISO and these are primarily time-differentiated rates, such as TOU and CPP.

So, once we did that and determined which program, which of the existing programs fit into which of these buckets, then the PUC set a deadline of January 2018, where all supply DR resources that utilities control would have to be integrated into the ISO markets by that deadline.

And there was a consequence if they were not able to, that they would not receive resource adequacy value for any program that didn't make that deadline.

I will highlight here Edison, just because Edison began, actually, its integration quite early, it was actually in the summer of 2015, so they're an early adopter of this. And they currently have about 1,000 megawatts already integrated, which is about 80 percent of their portfolio.

PG&E and San Diego, as far as I know, are on target to make the January 2018 deadline.

So, next year you will see, in the ISO markets, a lot of the IOU portfolios being bid in, registered at the ISO, and then being dispatched by the ISO by summer of 2018, or even earlier than that.

So, I want to raise the demand response auction mechanism to your attention. I think this is an important policy objective of the Commission. It was a pilot that was adopted in 2014. It's been running, now, for three years. And as you can see from those middle bullet points, the amount of megawatts that have been procured under contract from third-party providers.

So, the idea here was to see if there's ways to engage the market more proactively to get more demand response. As you saw from those previous slides, you know, up until 2013, the utilities were the dominant provider of demand response, with aggregators helping them. Aggregators, as I said, were supporting the utilities in their portfolios.

What the Commission wants to see is, is there a way to engage more aggregators. Is there a way to attract more demand response providers to the California market?

And so this pilot was created, it was adopted by the Commission. One of the reasons for doing that was let's expand the market. Let's expand and try and grow the resource and make it larger.

But what was also an important part of this auction; this auction mechanism is that third-party DR providers that won contracts were required to, as part of winning a contract, to provide supply DR. DR, again, that's bid directly into ISO markets.

So, that was the deal. If you win a contract, a capacity contract from a utility through this auction mechanism, the DR provider would be responsible for bidding, registering their resources, bidding it into the ISO market, being dispatched by the ISO, responding to ISO awards and so forth, so that it's visible there. And that's the way that we could help grow supply DR.

So, not only has Edison gained a lot of experience in the ISO market through the integration of its own portfolio, but these demand response providers, as well, have begun to learn through the last two years, now, what it takes to register their resources, what it takes to bid, and all the challenges of moving DR into this wholesale world.

So, as you can see, the megawatts have grown. There's been great interest in this program. It's up to about 205 megawatts, now, for the 2019 delivery year.

But there are questions remaining as to whether the pilot has been successful. If you just look at these numbers, you might declare it a success. But I think the Commission is wanting to know a lot more about how the auction has gone, and how have these demand response providers performed in meeting their capacity commitments to the utilities, as well as responding to

ISO dispatches when they're triggered.

And so, evaluation of the pilots is occurring. The Energy Division staff is doing that. We're looking at other questions, such as where new third-party aggregators engaged in this process, other than the ones that are already existing here, in California.

Were new customers engaged? In other words, how many of the megawatts that you see here actually are coming from people who had not done demand response before versus those who just simply migrated over from the utility portfolio?

And again, how have the aggregators, the demand response providers performed in meeting their capacity commitments to the utilities, as well as responding to CAISO dispatches when they're triggered?

So, all of that is being evaluated and we will have the results of that evaluation by June of next year.

And the Commission has stated, in a previous decision, that this evaluation will speak to the -- I guess, the question of the future as to whether the DRAM should move from a pilot to a full-blown program, you know, to be much larger than the megawatts that you see here. A lot of that will demand on, I think, the outcome of this evaluation.

Okay, goals. So, in a recent decision, back in 2016, the Commission adopted this goal. And it was an attempt to kind of consolidate, you know, three key principles that were emerging within the proceeding, such as assisting the State in meeting its environmental objections, which is GHG reduction. Cost effectiveness continues to be an important tenet there.

And, of course, from the customer perspective is DR helping them meet their energy needs at reduced cost?

So, this was an attempt to basically consolidate a lot of what has already been said in prior decisions, but putting it under one overarching goal that the Commission felt was necessary to continue to, I guess, communicate to the stakeholders what the priorities were from the PUC’s perspective.

There was, I believe, a megawatt-specific goal that was adopted by the Commission, dating back to 2002, I believe, 2003. And at that time the Commission had declared that the utilities should be striving to get 5 percent of system peak demand for price responsive DR.

So, that equated at that time to about -- I think it was 2,000 megawatts or so, 2,200 megawatts. And so, that goal has been in place for several years. I think it was repeated again in around 2014, in terms of a specific megawatt goal.

But this decision is really declaring a little bit more about -- I think the goals for the State should be more than just specific megawatt goals that we should be achieving but, rather, there's some qualitative things that we should be striving for. And I'm going to touch on that in this next slide because these principles were also adopted in that same decision. So, these provide a little bit more specifics on what the Commission's trying to emphasize for demand response going forward.

The first two are about flexibility, changing demand response to help support renewable integration. So, that gets back to being more than just a shed resource during peak hours. And DR can be used to help with that.

DR's evolving to help complement how the grid is changing. So, we can't stay in the current framework of just shed DR during the peak, although there is value to that, as well. So, I don't think the Commission is saying we need to get rid of that, but there needs to be new types of DR coming online.

Customer choice, another important principle there that's been adopted by the Commission. And the utilities are supporting that by eliminating batteries to -- again this issue of data access.

Coordination with rate designs. This was discussed I think primarily in the context of time-of-use rates coming in 2019, and other types of rate design changes. Making sure that customers are not confused by the different types of rates that are being offered, along with demand response opportunities.

That second-to-the-last point about processes being transparent, this is more about ensuring that stakeholders can see a little bit better what the Commission processes are, as it evaluates demand response. Whereas utility processes, there's some cases where there's been maybe a lack of transparency, so stakeholders could be benefitting from that when there's a little bit more of a transparent explanation of how things are working.

And then the last point about -- again, it comes back to the emphasis on third-parties. The services provided by third-parties and, again, that they're dispatched in the wholesale markets.

Then, lastly, customer data. So, again, this issue has come up recently as third-party providers have become engaged through the DRAM, they need access to customer data. Information about the customer, where they're located, are they in a DR program already. And, of course, what is their usage? And they need this type of information in order to see if they're good fits for the program and/or, obviously, if they're going to participate in the ISO market they need that customer data to settle over at the ISO.

And current State law and PUC policy requires that the utility obtain a customer authorization in order to release that data to a third-party. And the current process to do that, of releasing that data, is time consuming and difficult to complete.

It's primarily handled through a paper form. I think Edison has an online process. But either way, it's very lengthy and it's difficult. Many customers, at least from what we're hearing, have dropped out of the process. So, the demand response provider loses the potential customer in terms of signing them up to a third-party program.

And so, how do we fix this problem if getting data, this important data, to the third-parties, from the utilities, and yet maintain some level of privacy, some level of protection for the customer.

And so what's emerged, from about a year of work with stakeholders in a working group, is this idea of what's known as the click through. Where customers can authorize the release of their data to the utility by simply going onto a third-party site. The third-party enables a customer to click on a couple of new screens that pop up, which essentially go directly to the utility, where the customer authenticates his or her identify and says, yes, I am who I am by providing some type of information. Like account number, a zip code, so on, password. And then, authorizing the release of the data to the third-party. The third-party not being able to see any of the customer's credentials in this transaction, but the utility being able to see that and, thereby having the protection there to release it.

So, the hope is that this will make the release of data to third-parties much simpler, much easier, less frustrating for the customer. It can help accelerate the growth of demand response.

And so, we've got a draft resolution that approves the funding for the utilities to build the IT infrastructure to support this. I believe it's on the next Commission meeting agenda. And it's about $12 million that's been authorized for this initial start.

One issue that's been raised by stakeholders, who are not necessarily demand response providers, but they support other types of DERS, is they would also like to have access to the same data. Energy efficiency providers, solar providers, and so on.

So, as sort of a new application of this is, you now, expanding what's being built here for third-party DR providers to other users, other entities that would also like to get access to that data to help further DER expansion.

And then my last slide, I just thought I'd throw out a few issues that are going on at the Commission in terms of looking ahead what's in our proceedings, as far as policy issues that the Commission's trying to resolve.

Again, the future of the DRAM, if the pilots are a success, what changes, though, are necessary for it to expand successfully from a pilot to a large program.

New models for DR. So, as I said earlier, we don't have really any demand response today, other than a pilot at PG&E that incents customers to consume more electricity in certain times of the day. So, you might think of that flexible DR or bi-directional DR.

But how do you construct these models and what are the barriers to creating them? What are the policy barriers or the implementation barriers to that?

We're just beginning to uncover one of the issues there of this new type of demand response. One issue that's already been raised is the baseline. How do you measure the customer's load drop or load increase if their load keeps moving up or down? That's a really challenging one.

Default TOU rates. Again, that's coming in 2019. But how can we best leverage DR programs and technology to equip customers for the oncoming TOU.

And then this last point, recently again raised in our proceedings, is targeting DR to local capacity areas in disadvantaged communities, and what approaches should be taken to address that?

That's never really been debated before, as far as I remember, in any of our DR proceedings is that type of issue of targeting it in that particular way. What are the barriers to making that happen?

So, that's just some of the issues we're dealing with. There's actually several more, but I thought that this would be, maybe, a way to begin the panel discussions, if people want to get into those.

So, I'm happy to take any questions on any of these slides.

CHAIR WEISENMILLER: Yeah, let me start off with just a couple. I guess one of the things that would be useful to know is sort of what's been the total, so far to the Commission, with the demand response programs? It's probably interesting, at least, to bracket that with how much the interruptible rate programs will cost?

MR. KANESHIRO: The total cost of the utility portfolios?

CHAIR WEISENMILLER: The total cost of the requirements, yeah.

MR. KANESHIRO: Let's see, I know it's gone down --

CHAIR WEISENMILLER: And you can submit later. You don't have to respond, now.

MR. KANESHIRO: Okay. All right.

CHAIR WEISENMILLER: It would also be good, when you're looking at, sort of evaluating the pilots, trying to figure out from the pilot participants what have been the issues or the barriers they came up with. So, as we make the transition, you know, hopefully make the transition, we can also get a better sense of how to make life easier for them, along with how to increase the effectiveness for us.

MR. KANESHIRO: I'm sorry, I missed that first part, make it easier for the --

CHAIR WEISENMILLER: Basically, as you talk to the program participants, trying to understand what barriers they ran into and the things that we may able to -- you may be able to address as you go on from the pilots to the programs.

MR. KANESHIRO: So, the evaluation, you're speaking of the DRAM, right?

CHAIR WEISENMILLER: Right, yeah.

MR. KANESHIRO: Yeah. So, there is a lot of data gathering with regard to -- I mean, when you say the program participants, you're meaning the third-party demand response suppliers.

CHAIR WEISENMILLER: Exactly. Exactly, the DRAM marketers.

Yeah, to try to understand -- obviously, your job is really to look at it from the ratepayers' perspective in terms of how to make sure we're getting the value there, and meeting the basic targets.

But part of it is trying to understand from the marketers what might make it easier for them going forward.

I mean, frankly, you know, we've all been hoping for much larger numbers here and it's been pretty flat. I guess, probably, if we look back far enough and see the drop down in DWR, I'm not even sure we're making progress in the right direction.

So, again, it's going to be important to continue to push forward, making it more -- getting into the wholesale market. And the ISO stuff actually gets to some of the effectiveness questions.

But we're going to need a significant expansion going forward to deal with -- flexible loads to deal with flexible supply.

COMMISSIONER MCALLISTER: So, I just have a couple. So, just clarify, so you talked about the data issue in the context of settlement at the ISO. And I just want to be clear, so data has been an impediment for customers and aggregators to get the data they need to then go to the ISO and settle what actually happened. And so, I mean, it strikes me as a very critical cash flow issue for all involved. What kind of delays are we talking about?

MR. KANESHIRO: Well, it varies from utility to utility, I think. And there’s -- well, there’s delays in terms of just getting the authorization to release the data. So, under the current paper form the customer fills it out, or the demand response provider fills it out on their behalf, but the customer still has to sign it to demonstrate that they are the ones authorizing the release.

And once it goes to the utility, the utility must check to see if the information on there correlates with what they have on record to ensure that this is truly the customer. So, there’s a review that goes in there. I can’t recall the specific times, but sometimes it’s very quick, maybe a day. Other times there are delays because a customer might put in a slightly different way of their address. And so, it doesn’t correlate to what the utility has and, therefore, there’s a question whether this is a valid release.

COMMISSIONER MCALLISTER: Oh, okay.

MR. KANESHIRO: So, there are delays in regard to that.

But then there are times when once a release has been authorized, then getting the data from the utility to the third-party in order them to settle with the ISO, there have been at times some snafus, or you said breakdowns in the system. And those are being addressed in terms of fixing, either if it’s an IT problem, to fix them.

So, it’s kind of all new. The players of this are learning how to do this. And so, some of this is not that surprising. But, of course, we want to fix them as demand response continues to grow and the participants in the auction need to be able to settle with the ISO. So, we’re trying to eliminate as many of them as we can.

COMMISSIONER MCALLISTER: Thanks. I mean, we’re having similar discussions across the board with efficiency on this. I’m a little surprised to have this issue pop up in a type of activity that really does depend on timeliness to help, you know, do load shaping. So, it strikes me it's a little frustrating to hear this come up again, when these systems really need to be put in place and automated to the extent possible.

So, I would encourage us all to just fix this problem. It's just this shouldn't be that hard in 2017.

And let's see, just really the focus being on speeding up the process so that it actually can be a load resource, you know, a demand and supply resource in a flexible way, in real time. I mean, we've got to get the data to the people who need it so they can develop their businesses and have cash flow.

And I guess the other point on the data issue, it seems like this infrastructure that we're talking about building, it's great that there's a resolution on the next business meeting. It seems like this investment is, across the board, relevant for lots of other things that the Commission, that the PUC would be doing, and that the utilities would be doing with aggregators, and customers, and just setting up those systems. So, I hope that it's seen in that way and not sort of, you know, to the Chair's point, what's been the investment in demand response? Well, these are sort of housekeeping issues, really, just modernization of the IT landscape.

And I think that, in and of itself, you know, apart from DR, is really a necessary priority really across the board. You know, at all the agencies, not just at the PUC. But we're dealing with a lot of very similar issues getting information from the utilities for forecasting, for all of our processes on the doubling of energy efficiency, and all of the other things that are going on in parallel and in conjunction with this.

So, I would just, you know, in general highlight the overall value of that and not tag it just in DR.

And then, I wanted to just suggest that this is a liberalization, right? We've got more stakeholders, we've got aggregators, we've got lots more customers, hopefully. We need to make it as easy as possible for them. And so, I think this will be a recurring theme, but let's not lose sight of the customer. Like, this is a voluntary endeavor. Customers have to find this to be usable and sort of pain free. And so, the aggregators have to be able to go to -- in the evaluation, I guess is what I'm suggesting, is that let's think about what design parameters the demand response offerings can put in place, the sort of just program design to make it as sort of low transaction cost, friction free as possible, so that customers can participate with no hassle. And then, if the value proposition is there, somebody can sell that to them and then implement it.

So, I think that's really a key sort of design principle for this particular thing, along with energy efficiency, where it's really all up to the customer, so we have to make it worth their while.

So, anybody else? Thanks.

CHAIR WEISENMILLER: Thanks.

COMMISSIONER MCALLISTER: Thanks a lot, Bruce.

MS. RAITT: Thank you. Next is Jill Powers from the California ISO.

MS. POWERS: Good morning Chair, Commissioners, and the ISO. It's my pleasure to be here to give an update and progress on the ISO progress in meeting the 2013 IEPR demand response recommendations. I've been told I need to give four years of working effort in 15 minutes or less. So, I'll do that.

I won't be able to cover everything and all the actions that we've taken, so this presentation is to cover those related to barriers resolved through the development of additional demand response participation rules and market design, as well as the enablement of adopted policies, of four DR bifurcation policies for wholesale market integration, including the third-party DRAM participation.

These actions were taken and we received guidance based on priorities within the 2013 DR and EE roadmap, as well as priorities that were established through the Supply DR Integration Working Group. In addition to a multitude of ISO stakeholder initiatives, as well as technical customer partnership groups.

So, first off, and directly after the 2013 IEPR was published, the ISO was able to obtain FERC approval for the implementation of the Reliability Demand Response Resource Participation Model. And this was implemented in 2014, which was a big enabler for the integration of the utility retail emergency-triggered demand response programs which began in 2015.

In addition, the ISO was able to enable the provision of spinning reserve from proxy demand response in 2015. And this was undertaken once WECC allowed, changed some definitions to expand load participation in spinning reserves.

So, with that implementation we were able to obtain some operational experience with San Diego Gas & Electric’s Optimized Pricing and Resource Allocation Project, which began with non-spinning reserve participation and then was able to move into spinning reserve market participation in 2015.

In addition, we have completed and have

additional market design enhancements in progress to meet specific DR and EE roadmap goals that were presented in that roadmap.

We've completed the Flexible Resource Adequacy Must Offer Obligation, which was an initiative that was implemented in 2014. And this initiative was an initial step towards ensuring that adequate flexible capacity is available to address our changing grid needs.

And it includes technology, agnostic flexible capacity categories that is accessible to demand response in the Category 3 super peak flexibility.

In addition, we have an ongoing initiative, Commitment Cost Enhancement, in its third phase. It's scheduled to be implemented in September of 2018. And this will provide use-limited resources opportunity cost adders for startup, minimum load, and bearable energy costs.

There are other reliability service initiatives that are in various phases of implementation and stakeholder process, but we wanted to call out these two specific ones that were completed and are near completion.

One of the items that really wasn't in any of the supply integration working group priorities, but which we believed, based on our customer participation group meetings, and priorities within that was an improvement to modeling methods that we made to reduce the implementation time frame for distributed energy resources to bring their resources to market participation.

This enhancement was developed and implemented in 2016. It gained efficiencies in the processes around DR registration, as well as it allowed ISO to obtain some additional efficiencies in our own network modeling processes.

So, now this allows for any DER resources to be created on demand, without a full network model update that can take up to a six-month time frame. So, you can see we've shortened the need to go through a full network model that could take about six months, down to just having that available on demand.

It significantly reduced processing timelines, as well as management of request for new resource IDs by our demand response participants.

As well as it simplified the request to customize the modeling of these demand response resources.

And I wanted to add that this implementation was completed during DR integration activities, participant activities for both the utility programs, as well as the

DRAM participants. And it was this modeling enhancement which was used to enable our next priority, which was the successful implementation of the Sub-LAP realignment. And this was a priority that the Supply DR Integration Working Group had called out.

So, in 2016, the ISO performed a study and then redefined existing Sub-LAP boundaries. And this realignment helped a demand response provider know if their resources were fully within a local RA capacity area.

Since demand resources are required to be aggregated within a Sub-LAP, this realignment aligned the Sub-LAPs to be within these capacity areas where we had them sometimes crossing the capacity area. So, this is what this realignment was about.

And this was implemented beginning January 1st, 2017. And again, this required significant coordination with our demand response providers that were integrating DR for resource adequacy commitment.

Additionally, we took on a priority of relaxing telemetry requirements based on recommendations from the SIWG. What this did was to relax current ISO requirements in terms of the time for scanning the sub-resources within an aggregation. So, this requirement was expanded to a five-minute update from a one-minute update, but specifically for day-ahead and real-time energy market participation.

And this was implemented with a BPM change, Business Practice Manual change in 2016.

Some significant technology upgrades that were made to our systems supporting demand response integration were made in a stage development between 2015 and 2016, but we were able to complete that by 2016.

So, our first phase was to provide additional application programming interfaces needed for bulk loading and downloading of locations within our demand response registration system. So, this was successfully deployed in 2015. And it allows for the successful 2015, as well as 2016 utility program, and DRAM integration for them to utilize this initial functionality.

So, the first phase was to provide those application program interfaces.

The second phase was deployed in November 2016. And again, this deployment was based on feedback that we received from our customer partnership groups as to priorities and enhancements to the registration process.

So, in 2016 we provided a system that was a unified registration processing system and additional requested APIs from our participants.

As we all know, new systems come in, but there's always requests for additional enhancements. So, we're continuing to work with our participants in 2017 and just this past Monday, yesterday, we had another partnership call to capture and deliver on additional application enhancements requests we have seen since our 2016 deployment of the second phase.

Now, with successes in 2015 and 2016, they always come with challenges. We had an uptick in integration activity in 2016. We had our system enhancements in 2015 and 2016.

But we did have some challenges. And these challenges came in some performance degradation that we had with our legacy demand response system, one that we are attempting to redevelop and actually retire that with our redevelopment of our demand response registration system.

And this did result in settlement statements that were processed using incomplete and/or missing performance data. This happened toward the end of 2015, early 2016. We were correcting these errors as they were observed, but then there was a determination and understanding that there was a larger problem. Root cause analyses were done and ISO completed a comprehensive evaluation of all the observed system failures that resulted in this inaccurate data, as well as the lack of settlement. And we've taken full corrective actions for all of the dates identified.

So, all of the 2016 performance data has been reprocessed and it will be reflected on what we term as the next available settlement recalculation statement. Meaning that we could correct the data, but there are timelines around recalculation statements -- timeframes around those recalculations. So, data will be made available to the next available one.

What I've learned is that the full resettlement should be completed by October 2017.

Additionally, with this comprehensive review, that evaluation we did, we've put in additional monitoring of the overall demand response processing, along with responding to all of our DRPs' inquiries. And we've really intensified our efforts in being swift about correcting errors that are identified either through the ISO's monitoring or those that come to us through our demand response providers.

And lastly, the whole technology effort was to get us to a point where we will be able to fully replace our legacy demand response system. And that is something that we're looking at having completed in

2018, with the new, robust demand response registration in place, as well as robust meter data management systems that will be utilized.

Both from our participants, as well as through the Supply Integration Working Group, baselines was one of the big actions that needed to be done for us. New baselines were requested and we were able to provide those through our energy storage and distributed energy resource initiatives, both which have been completed.

The first one was phase one. Implementation occurred in 2016. This provided additional baselines recognizing behind-the-meter generation, as well as it implemented statistical sampling methodologies that could be utilized, where meters that did not have 15-minute -- were not available with 15-minute data could be utilized and to have statistical sampling used to obtain that meter data.

Secondly, and just recently the Energy Storage/Distributed Energy Resource Phase 2 initiative was completed and will be implemented in 2018. And this adds three additional load baseline methodologies.

And these load baseline methodologies came from a utility-led working group that did some extensive analysis, evaluation, and proposed these three different performance evaluation methodologies for various types of DR. Those would be control group, weather matching, and additional day matching baseline methodology.

And again, those will be implemented in 2018. We're currently working on our implementation plans for that.

Thirdly, we are in the process of a third phase of energy storage and DER initiative, and we're in the process of developing an issue paper. That's in development and will be published in September.

Okay. So, in conclusion and with an eye on the duck and with experience gained from DR market integration activities in 2015 and 2016, we've come up with these ideas of what may be needed to best position DR to address the needs of California's transforming grid.

And someone pointed out to me today that I appropriately wore a shirt that has a flying duck on it. And that's exactly where we want to get to. And that's where a lot of these come from. And this is, I think, the theme that we will be seeing.

So, we've point together these points. One of them being more time-variant rate options that align with grid needs, I think you'll hear that theme, to shift and shape load to create a flatter profile. And, hence, the flying duck. More flexible DR program designs tailored to customer capabilities, aligned with grid needs, with more agile designs than the one-size-fits-all is what we've seen to date.

The ability to combine multiple retail programs into wholesale DR resources, to capture synergies, to create flexible attributes.

More robust DR dispatching systems and algorithms. We need the capability to have incremental dispatch to help balance the system.

And some other efforts that this could help with is to have precise locational dispatch capabilities.

And lastly, greater real-time visibility. More visibility is needed. We know that. But how do we get there? And we know this is going to become more and more important as distribution operations are impacted by high DER penetration. Greater visibility is needed, so we're trying to put that as a bullet point.

A couple of ideas I think that has been explored; telemetry as a service using existing advanced metering infrastructure. There was a report that was published by PG&E that looked at this.

And then we've been doing a lot of work with our utilities on DER integration, as well as the DR integration. So, there's really more need in exploring alignment between the transmission and distribution system visibility needs and telemetry requirements.

So, I think that's it. I think I did it in ten minutes, four years' worth of work.

CHAIR WEISENMILLER: Okay, great. Thank you. Thanks for your presentation.

A couple of follow-up questions. The first is in terms of getting the new settlement system in place, exactly when in 2018 are you going to do that? Obviously, sooner is better than later.

MS. POWERS: It's not a settlements replacement.

CHAIR WEISENMILLER: Okay.

MS. POWERS: We've already replaced the functionality for registration with our new demand response registration system. The old system, the demand response system had some additional meter data management, as well as some baseline calculation functionality. And those will be moved into the appropriate metering systems, which has already been developed and implemented in 2016.

As well as there's been some changes with our ESDER initiatives, where we will be depending on our demand response providers to be actually calculating any new, as well as existing baselines, and submitting the results as meter data to this new system.

So, there's been some changes with the

initiatives as to how we're approaching the settlement piece of DR.

CHAIR WEISENMILLER: Right.

MS. POWERS: And that system, we're looking earliest 2018 spring. But that's the absolute earliest right now. We are in the initial implementation planning phase.

CHAIR WEISENMILLER: Okay. The other question, there's been a recent report that alleges that with the more and DG inverters that that opens up potential loopholes on the hacker or cyber security issues.

So, as we move forward on the IT side, trying to link utility, customer and you, I'm just trying to make sure we have at least some assurance that you guys are thinking out ahead on the cyber/hacker questions.

MS. POWERS: Yeah, and with both our DR and DER, you know, we've been looking at that, you know, for particularly with interactions with our aggregators.

CHAIR WEISENMILLER: Thanks.

Andrew?

COMMISSIONER MCALLISTER: I don't have any specific questions, just thanks a lot. I mean, hopefully, you're going to be around so we can maybe take advantage of your presence here, throughout the day, but thanks.

MS. POWERS: Yeah. Okay, thanks.

CPUC COMMISSIONER GUZMAN ACEVES: Thank you, Jill. I did have a follow up. I think it's really interesting to see if there's a future of the system DR needs and what kind of product that we may need there, and the local needs. And you mentioned, in this slide, on precise locational dispatch, is there -- can you describe what that looks like to you? Is it at the Sub-LAP level or what do you mean by local?

MS. POWERS: I think what we're experiencing, with our discussion with utilities as a distribution system operator, that there may be needs and times where, although we may, at the transmission level be needing specific services. There may be difficulties for parts of the aggregation, based on the way that the distribution system may have some outages or changes to their system that won't be available.

So, it's no longer about the aggregation over the full Sub-LAP, which is what the ISO would look at, but it's really about now looking at, well, what is the impact at the distribution level?

And we're seeing this more on the DER side, where there's the potential that parts of an aggregation may not be available at any given time, based on the profile of the distribution system.

And so, I think that's where we're trying to get at, that there may be more precise dispatching that needs to be done for these types of aggregation.

COMMISSIONER MCALLISTER: Can I follow up on that, actually?

MS. POWERS: Okay.

COMMISSIONER MCALLISTER: So, do you have a sense, or maybe this is part of the issue paper that you're coming up with, but do you have a sense of what would be sort of a scale that those issues would come into play? Like, you don't have issues at the transmission level that you would need to dispatch some DR to solve, but at a local level you do. And maybe the utility is telling you, oh, yeah, I've got this congestion issue that's local.

Do you have a sense for sort of how many megawatts, over what sort of load area -- you know, what the scale of that would be? How many megawatts of DR, how many -- you know, the load in that particular local area? Has that been an effort of -- you know, have there been conversations about how local is local enough?

MS. POWERS: Not a sense of the extent or the values, just really the discussion is about what impacts there may be at the distribution level that would impact an aggregation that's providing services at the wholesale level, and the fact that some of it may not even be available because it's in an area that may have -- may be out within that distribution system.

So, it's something that the ISO doesn't have visibility to. And we're really on the early stages of discussion on this, more on the distributed energy resource side. But it's just something we kind of put out there that in the future there may be the need to have this capability of more locational dispatchability.

COMMISSIONER MCALLISTER: I guess the question really would be -- you know, many, many questions around this. But in terms of the PUC, and the ISO, and sort of where the ISO dispatches and then where they had off, where it becomes a local problem is really at the distribution level purely for the utility. Like, what does that handoff look like and how can it be seamless?

MR. CASEY: Now, we've had a utility ISO working group the last couple of years, working precisely on that issue which is how do we coordinate. As we get these distributed participating as a transmission resource, how do we ensure that the dispatch we're giving to these aggregations worked on the distribution system? So, there's a whole suite of issues that the utility is concerned about, understandably, and this is one of them.

Because when you have an aggregation of a Sub-LAP it could be, you know, a dozen distribution feeders that comprise that, and maybe some of those feeders it's just not feasible.

So, how do we work through that issue? Do we de-rate the aggregated resource? That's an option.

Or, as Jill said, do we look to see if we can come up with a way to actually allow the aggregated resource to do a more locational dispatch with the distribution system?

So, these are issues we're working through. But it's a very challenging area figuring out we coordinate all this. And it just underscores, you know, the importance visibility and control. Those are really the key things that we really have to not lose sight of, that we're moving to a system that's going to be highly decentralized, and we're going to need visibility and automation to manage it.

And so I know telemetry is a challenge for DR resources and we're trying to work through that. But the answer is not we don't need to see the resource. We absolutely do need to, as both a transmission operator and as a distribution operator.

COMMISSIONER MCALLISTER: Thanks.

CPUC COMMISSIONER GUZMAN ACEVES: Just to kind of overlap the earlier point which is in addition to that, we are -- it seems like at this point we're really focused on DR meeting the system transmission needs. And perhaps there's an opportunity, in this new world of DERs playing into distribution and local, and system needs, that there may be some opportunity to look at the local needs and the distribution needs. The local transmission needs and the distribution needs for some optimization.

And, you know, certainly, thinking of, in general, the local needs being more emergency-based, giving us some flexibility there. Whereas, some of your system needs may be more frequently called and have more of that complexity. On the local need, it may be -- I don't want to use the word "flexible" because that will just confuse it all, but may give us more opportunity.

MS. POWERS: Okay, thank you.

MS. RAITT: Thank you. Next is Mary Ann Piette from Lawrence Berkeley National Laboratory.

MS. PIETTE: Good morning. I want to thank Chair Weisenmiller and the PUC, the CEC, and CAISO for the opportunity to present this study to you, today.

I want to give a special thanks to the Public Utilities Commission that sponsored this work. Unlike

Jill, I'm not reporting on four years' of work, but two years of work. And I have over 30 slides, so I'm going to go through the high points.

But this is a study that's available on the PUC's website. If you have trouble finding it, let me know.

I'm going to start by thanking the authors that you see listed here. And we had a team from Lawrence Berkeley National Lab. E3 helped us with the RESOLVE modeling that we did, that I'll talk a little about.

And then Nexant worked with us on the propensity scores and how the DR adoption was modeled.

I'm going to start with kind of an introduction and an executive summary. So, I'm going to give you the results of the study and then I'm going to go into more detail about how we did the study, and what the recommendations and next steps look like.

So, the concept of this study was that as we -- as the PUC was looking at bifurcation, we were exploring the value of demand response in the load-modifying category, and then the supply side DR that was integrated in the CAISO markets. So, we were part of the OIR, related to DR, to help understand the potential for DR in meeting the State's goals.

And the most important thing to understand is we were interested in how much DR is in California and what's the value of it. And that later challenge of what's the value of it, we developed a set of supply curves, which I'll explain to you how we did that.

And those supply curves then become the basis for deciding what the different valuation methodologies are. So, we were developing these supply curves.

Now, we used four different grid services in this study. The traditional shed, which we've had for decades in California, but we introduced a new concept of DR shift. We did not do a take product. Instead, we call it a shift. So, shift means that it's approximately energy neutral over the day.

We didn't want to just take load and then do something with it, we wanted it to shift the load. So, we defined a shift. So, we did a supply curve for shed, a supply curve for shift, and we also did supply curves for shape. And the shape idea was in the load shaping bifurcation agenda that the PUC has been developing.

And the tariff design here, on this graph, actually shows you a super off-peak rate, where the lowest price is in the middle of the day. And that's a groundbreaking concept for California, that you would actually change the shape of electric prices.

So, the prices-to-devices concept is being considered and modeled here. And I believe that's one of the most -- the biggest possibility and activity for us.

And I'm also going to show you what I call shape shift, and shape shed. Because these things are not singular.

And then, shimmy is the fast DR. Shimmy is the ancillary services and shimmy is a sort of continuous resource that we modeled, as well. So, we have supply curves for shape, shift, shed,and shimmy, and tango, and things like that.

So, this is a graph that shows you the shift, shed, and shimmy, and the grid services that they provide. The shed, the shimmy are in Kw, but we actually did shift in energy terms, so daily energy shift.

And then on the right column, you see that I also said that shape can provide shift and shed. So, there we go.

This graph many of you have seen and the time scale of flexible load can be characterized into these four different concepts of shape, shift, shed, and shimmy from years and seasons to hours of the day, to minutes, and seconds. So, these four categories of demand response, there's a lot of overlap between them.

But essentially what we did is we modeled customer loads and we explored how much demand response is available in each of these areas by the different categories.

This slide is an important description of what we did. We have over 200,000 customer load shapes. So, we basically recreated the 8760 demand curves for 2014, 2020, and 2025. And we took the State's load growth and a variety of scenarios looking at how loads are changing over time. And we clustered the data. And I'll explain a little bit about how we did the clustering.

So, we had 200,000 hourly load shapes from customers throughout California. We had 11 million demographic files. So, we created a dataset that describes the end uses and the customer segments of all customers in California.

Then, in the DR Path system we said what DR is available from those customers? And that depended on what end use. Was it air conditioning, was it pool pumps, was it EVs, and how much did it cost for that technology? What are typical penetration rates for the adoption of the DR.

And then we used RESOLVE as a simplified production cost model for the future to tell us how much value do we get from the DR. And I'll show you a little about how we did that.

All right, so we used two different approaches. This was a two-phase study. And in phase one, all of the supply curves we did shed only. But we used a price referent. So, essentially what you have here is on the Y axis it's dollars per kilowatt per year. That's a levelized cost for demand response.

And as I'm going to show you in a second, those curves are made up by over 3,000 customer segments that are the different clusters. And the DR is available by different end uses. And I'll go through exactly how we did those end uses.

Then on the X axis is how many gigawatts you get as you stack up those DR supply curves. So you do the cheapest ones first. And you can slice and dice the supply curves various ways. But essentially what we did was we created a model of the DR available in California.

On the right graphic you see the price referent, which has the 200 bucks a kilowatt for a peaker, and that is one example of a price referent you can say anything below that 200 bucks a kilowatt will be cost effective DR. And so, some of the cheapest might be residential air conditioning, commercial building HVAC loads, and they stack themselves up.

So you'll find we have Sub-LAP level data, by customer segment in the model. And in certain parts of the State, where there's a lot of air conditioning, you're going to see the DR. So, we're going to actually help provide models of the DR available at the Sub-LAP level.

The second way we did it was the red and gold-colored curve on the right is from RESOLVE. So, we would model the DR in RESOLVE and we would value that DR based on the RESOLVE modeling, and create an intersection between the supply curve and the demand for the DR, in a sense, based on the RESOLVE modeling which values the DR in the market.

Now, I will explain to you some of the pros and cons of this methodology. It's not perfect and it doesn't include the air quality emissions that were mentioned earlier, for example. But it provides a market integration scenario for demand response.

Here are some of the key findings. We found about a gigawatt of shed from prices in 2025, and that's the medium scenario. So, we did a business as usual DR, a medium and a high penetration. Depending on customer engagement in the DR and about a 2 gigawatt hour shift from what we call the shape. So, that's time of use and critical peak pricing.

And shed, we get approximately 2 to 10 gigawatts depending on the different price reference that you do. And about half of that, which I'll talk about later, is in capacity-constrained distribution areas. So, we do have some information in the model about the shed available at the distribution system.

The shed was not greatly valued at the transmission level. Most of the value in the future is probably going to be at the local distribution system. If California has plenty of capacity, then the shed doesn't have a lot of value. But the shift had more value.

So, the shift we have 10 to 20 gigawatt hours. That's about 2 to 5 percent of daily load, and that's worth about 200 to 500 million a year for that shift product.

And then shimmy is, as many of you know, it's worth more per kilowatt or megawatt, but we don't need as much of it. So, we're estimating about 300 megawatts of load following. And that should be an "and" 300 megawatts of regulation at about $25 million a year.

Now, what could we be doing to achieve DR? We do think that there's opportunities to improve our penetration of dynamic price response and get more shape DR, combined with automation. Maybe automation of TOU response as you change seasonally.

Shed is, as I mentioned earlier about half the shed is in resources in local capacity areas. So, of course, the areas of California with the most load growth. And aging systems are a problem.

Shift is a challenge for California because it means thinking about electric load shapes and what are the kinds of things to evaluate the baseline settlement issues on. But there's a big opportunity because shift has a lot of value and it might be something you do every day. So, is it DR or is it a continuous response?

But essentially what you're doing is trying to incentivize customers to have a different load shape.

And then shimmy, the markets are thin, but there are good emerging capabilities in many end use loads to provide that service, as well.

Now, I'm not going to go through all of these bullets because I don't think I have time. But essentially the concept here is that demand response can help meet our operational challenges associated with high renewable penetration. And the loads have an important role to play.

So, I have some numbers here about the shift value, $700 million in 2025 that's 20 percent shiftable. And shimmy, the value in 2030 is more than in 2020. So, we're going to continue to see more renewables on the grid and the value of the shift is important to invest in, and start to try to build out that capability.

And then, I'm going to go onto the next slide. Let me share with you what these customer segmentations look like. We had over 3,500 different customer load shapes. So, these are archetype load shapes. In the residential sector the median cluster had 11,000 customers in a cluster. And that cluster is in a Sub-LAP, and it has 200 electric load shapes that make it up. So, it's an average load shape for a customer, for a residential customer.

Industrial, you can see the average time series datasets, 8760 data sets were 15. So, we had industrial clustered by NAICS Code. And we looked at different kinds of industrial segments.

And the commercial buildings, we had a variety of different kinds of loads that we modeled. So, we had -- that's the resolution of the model.

And these are the different end uses that we modeled. We modeled a behind-the-meter battery. And we modeled plug-in hybrid electric cars, as well as fully electric and the hybrid ones.

We modeled air conditioning and residential pool pumps, HVAC, lighting and refrigerated warehouses, process DR in large facilities. Ag pumping, data center

DR, and wastewater DR.

And you see a description there of the technologies. Those technologies, we collected data on how much it cost to install them. And the model assumes that there's no DR today. You will find we're paying for all of that DR in this model, and installing different kinds of automation.

You need the faster automated DR for those shimmy services, which are more expensive than the slower-shaped systems. So, we modeled a variety of different technology scenarios.

The costs included the cost to install the DR, as well as to operate it. And as I mentioned, we looked at the speed of the response.

So some end uses, for example like air conditioning can provide shift, but lighting cannot. Lighting is a shed service and a shimmy, pretty good shimmy, but not a shift.

So, we looked at what loads have inherent storage in them and those are the ones that are considered for shift.

And then we looked at what the history has been about the customer adoption. And we have a variety of scenarios, business as usual, a medium, and then a high penetration where more customers adopt the technology.

These are what the hourly load shapes that we created for 2020 and 2025. So, this is aggregating all 3,500 clusters. And we recreate the hourly loads and you can see that these look like the duck curves. And you can see the red is 2025, the blue is 2020. So, we have a deeper belly and a higher peak in 2025.

Now, just to get you a little bit more oriented on how you read a supply curve, we have again the levelized costs on the Y axis, which is annualized cost per kilowatt, including the technology, the financing, and sort of an aggregator-managed portfolio.

The cumulative DR on the X axis, we did a 1-in-10 and a 1-in-2 weather. So we did a 1-in-10 would be a hot year. And then, a 1-in-2 is an average year. And then we did this base year, this business as usual, a medium and a high. So, we had a variety of scenarios on what the uptake of the DR looked like. We tended to use the medium scenario as the base dataset.

In the supply curves we also considered things like the market revenue for the participant and the co-benefits of energy efficiency. So, we tried to consider the fact that the adoption -- the likelihood that a customer would participate in DR is influenced by their economic incentives, and that was modeled in the scenarios.

I only have one slide on RESOLVE. And RESOLVE essentially helps us see that the economic curtailment and the renewable over-build can be managed with a default solution and flexibility. So, we can have avoided costs of the power system.

The first bullet there says sizing the electric system to deliver every megawatt hour of renewable generation is cost prohibitive. And the concept here is that the demand response helps us meet our renewable goals by giving us tools to help manage the electric load shape issues.

So, the RESOLVE is like a simplified production cost model and we modeled the DR as part of the market, using E3's RESOLVE model.

This is a slide that gives you an idea of all the factors that are included in the propensity scores, which are the element that causes the adoption of the DR. So, we look at which customers are eligible, what the incentive levels are, what the enrollment rates are. And the kinds of things we've seen in the past on the models that are done to say who's going to participate.

And, of course, the high electric users, for example, with residential air conditioning are the ones that tend to participate.

This is a second slide from Nexant on the propensity scores. This is something that in some sectors we had better data than others, and it's one of the areas that could use additional work.

But in general, somebody was asking earlier what some of the barriers are for the aggregators, and it's recruiting customers, and communicating with customers why they should get involved. And getting the DR to persist. We need to be doing more work on getting persistent DR.

Now, this is an exciting curve. The blue on the right side is that rate from SoCal Edison, option 3, in the spring where the lowest price is in the middle of the day. The green prices are good, but the super off-peak rate is in the middle of the day.

So, can we get air conditioners to pre-cool before the duck curve? Before the neck of the duck, before dinnertime. That really is something we want to do. Can we charge our cars in the middle of the day, because we charge our cars when we get home?

So those are the things that we want the signals from the tariffs to start to incentivize behaviors that deal with the duck curve.

This is the gigawatts that we get from the tariffs, that Bruce mentioned, and I'm looking forward to Ahmad's talk. But we have about a gigawatt from rate mix 2, and 0.8 gigawatts from rate mix 3. But I also don’t have a shape shift. That option 3 would give you more of that shift. And again, we’re defining what that means for tariffs to give you shift.

So, revisiting the concept of this study, the concept is that the shift service would provide an energy-neutral load management. It would help with ramping, and lower the system peak, and avoid renewable curtailment. So, we’ve defined it as gigawatt hours per day and levelized cost per kilowatt hour per year.

So, there’s a variety of end use loads, as well as batteries and cars that can provide shift.

This is what a shift supply curve looks like. this is a 2025 supply curve, with these co-benefits. And you can see the high curtailment and low curtailment RESOLVE models. And we’re getting about -- the blue line -- let’s see if I can get my mouse here. I don’t think so. I’ll do that.

But the median green line there is you get between -- you get about 16 gigawatt hours per day, at about $25 per kilowatt hour, per year, with the shift resource.

Here are three of the end uses that provide some of the shift, commercial HVAC, industrial process, and industrial pumping. So, those are under that $50 kilowatt hour price referent. And there are, obviously, electric vehicles and batteries can be significant, but they're still pretty expensive for the battery.

So, we did model behind-the-meter batteries in general and use loads were cheaper than the batteries.

The shed service, this is calculated in terms of the gigawatts per year. We looked at the top 250 hours. It's interesting to note that over the next decade the top 250 hours change from just the summer to different times of the year. We actually found one of the top 250 hours in January, around dinnertime.

So, the problems that we're facing are kind of spreading out over the year with greater renewable generation.

These are what the shed curves look like. I have two. This is the price referent and the levelized system cost one. the price referent, we get about 6 to 10 gigawatts for the different scenarios we looked at, if you use that $200-per-kilowatt price referent.

So, that's where those are the stacking up. We also have the time-of-use and the critical peak pricing. That orange bar showing you we did the -- that's the shape shed value and we did a Monte Carlo analysis to look at some of the variation, which is the scenarios there give you.

There's a lot of uncertainty in the datasets, but the central tendencies are the most important aspects of the electric load shapes.

Shed has much less value in the RESOLVE model because of plenty of capacity over the next 10 years. So, I'm going to make a comment on that at the end. But we did not find a lot of value in hot summer shed because of the capacity in California.

This is what the -- if you take that $200 price referent, this table and these graphs show you which loads give you the most DR. Industrial processing, industrial pumping, commercial HVAC and lighting, residential HVAC, and plug-in hybrid vehicles.

So, you can see those are the end uses that we found to provide the lowest cost shed DR.

The shimmy, we did a load following and a regulation, like a continuous 5-minute dispatch and a continuous 4-second system. And we did those two types of gigawatt estimates with the model. That was also modeled with RESOLVE. And RESOLVE has that high time resolution capability for us to model the shimmy, and I presented some of that earlier.

This is my second-to-the-last slide. I have a couple of comments about policy direction. We've done the study in order to try to create a data-driven methodology for the energy analysis in California. We have defined this new concept of shift and what the rate design opportunities are for both residential and nonresidential customers.

So, there are new opportunities with new, emerging price forms in the policy world.

In the technology area, shift as energy demand response is, again, a new thing we're introducing. We've been continuously talking with the PUC about the link between energy efficiency and demand response, and how to do integrated demand side management.

Interoperability and standards really help reduce the costs of demand response, and so we've been looking a lot on what's the uptake of standards for DR?

And what are the distribution system automation linkages, which we talked about a little earlier. So, the model actually gives us some visibility as to where the issues are, what are the most distribution-constrained regions of the State?

This is my last technical slide. Again, more work needed on how, when somebody invests in energy efficiency, the DR gets brought along. Because customers don't distinguish, they just care about their bill, and they really want to make it simple, kind of a one-stop shop.

We are, as I mentioned, interested in possibly looking at more of the distribution system value of the DR. Looking more at shift technologies.

That second-to-the-last bullet is really important. The study has not looked at forecast DR and emergency DR. It's market-based DR. So, that's one of the areas we think we need to do further work on. Because in May we had an emergency, and we had hot weather, and we got less wind than we thought, and that's when we need our DR.

But this model doesn't really account for that, so that's an area we know we need further work.

And then my last comment is we need better partnerships, communication, and guaranteeing performance so that the customers, when they sign up for something, make sure it performs and the customers have some transparency in that.

So, my last slide is the Technical Advisory Group that we worked with. I wanted to thank them all. We had a lot of discussions with the utilities, and many of the stakeholders, so we really appreciate many of them are in the audience today.

So, I'll stop there and take questions.

CHAIR WEISENMILLER: Okay, thanks. Actually, given the time management issues, I'm going to skip questions, and certainly encourage others to be brief on questions. It was a great presentation but, you know, you can't cover 35 slides in 15 minutes.

MS. PIETTE: Well, I got a half-hour.

CHAIR WEISENMILLER: Yeah, but anyway, enough.

Anyone else?

COMMISSIONER MCALLISTER: Hopefully, you can stick around.

MS. PIETTE: Yes.

COMMISSIONER MCALLISTER: I mean, I think there's going to be a robust discussion I think about a lot of this, and on the other panel. So, we don't have to only -- hopefully, we have more opportunity than just now to question.

MS. PIETTE: Right. Sure, right. Thank you.

CHAIR WEISENMILLER: Great, thanks.

MS. RAITT: Thank you. So, we'll move on to our first panel, which is a discussion on Barriers to Meeting Demand Response Goals, moderated by David Hungerford at the Energy Commission.

So, if panelists could go ahead up to the tables, we'll have a place waiting for you.

MR. HUNGERFORD: Good morning, my name is David Hungerford. I work in the EPIC R&D Division of the California Energy Commission. And I am pleased to be moderating this panel of stakeholders in the demand response space.

These folks have all been involved in demand response in California for a long time. They have common extensive experience and a deep understanding of DR policy and implementation issues.

First, we have Mona Tierney-Lloyd. She's Senior Director of Regulatory Affairs at EnerNOC. She has 30 years of energy experience in shaping wholesale and retail market opportunities for utilities, retail suppliers, and distributed energy resources.

She's worked at EnerNOC for nearly 9 years on developing DR policy at the State level and in wholesale markets.

And, apparently, yesterday, or day before, EnerNOC was acquired by NL Green Power North America.

Welcome, Mona.

And following that we have Erica Keating. She is Senior Manager at Southern California Edison, where she manages the Large Power Demand Response Group that oversees DR for business customers.

She originally joined the company in 2010 as a member of the Energy Procurement and Management Division, where she managed various procurement efforts, including resource adequacy, renewables, natural gas, storage, and others in the SCE portfolio.

Jamie Fine works for Environmental Defense Fund, EDF, to reduce the impacts of energy systems used to power buildings, transport and to service people, and produce and move goods for EDF.

His areas of research and advocacy include design and implementation of market-based policy, modeling the economic, air quality, and health consequences of policy decisions, deploying smart grid for environmental and electricity customer benefits, and facilitating the meaningful involvement of community stakeholders and environmental planning.

And Dr. Barbara Barkovich. After working on energy and environment issues for the National Science Foundation, she spent a number of years at the California Public Utilities Commission, finally as Director of Policy and Planning.

Since the mid-eighties she has been a consultant and expert witness on energy, especially electricity, and regulation including marginal cost, cost allocation, and rate design, industry restructuring and demand response.

She’s negotiated on the behalf of industry electric consumers with utilities, on pricing and service.

She is now Chairperson of the Board of the restructured California Power Exchange. And she served on the California Independent System Operator Governing Board, and the Energy Engineering Board with the National Research Council.

Thank you all for coming today.

All four of them have provided extensive, detailed presentations, which were available out front, and will also be available on our website. So, they provide the details of their comments and their responses to this set of four questions that we're framing this panel around.

But I think, especially given the time, that I think it's going to be more interesting and more useful to have these people just discuss with each other their thoughts on these questions. And let us listen in on this discussion. And I know I'm going to learn something.

So, I'm just going to start, throw it out, and let whoever speaks first respond.

The first question is just a starter. I'd like for you guys to characterize the progress, from your perspective, that California has made in expanding DR participation, as the goal in the 2013 IEPR, over the past four or five years?

Barbara?

MS. BARKOVICH: Well, it depends on what you mean by expansion. Because if you look at the slide that Bruce put out, you can see that the number of megawatts hasn't necessarily changed.

I think there are reasons for that that we can explore here today. And I think one of the reasons is because there's been a re-thinking of what DR is supposed to accomplish.

I happen to be one of those people who firmly believe that it still has a role in providing reliability and dealing with contingencies. And so the real issue is what else can it do and how do you make it do it?

And I would say that all of the PUC has had a goal for some time of integration of demand response into the CAISO markets.

It has been, as we have been doing that over the last several years that we have discovered that it's not simple. Jill pointed out some of the issues including the IT issues.

I personally have been involved in a bunch of those issues, as have other people on this panel.

So, I think the reason we don't have more megawatts is because we're trying to evolve the kinds of megawatts and because integration isn't simple. And I know one of the things that I would like to speak to, as probably Mona and Erica will, are some of those barriers and how to overcome them.

So, I think in terms of some of the other areas in which we've made progress, I will leave that to the others.

I think there is some evolution in the mix of customers. The different, potentially, kind of participation by smaller customers, which is part of the evolutionary process that's beginning to happen. And that's a good thing.

But given that we have limited time, I want to save my fire power for barriers and how to overcome them.

MS. TIERNEY-LLOYD: Thank you. So, EnerNOC has been a participant in the California market, providing demand response services since 2007. So, we've seen a lot of evolution in what demand response resources are asked to do.

And I would say the one observation that I would make for now, and for going forward, is alignment. To make sure that we have as much alignment as possible across State agencies, as to what the goals of demand response are. And that we communicate that need to our customers, both in what we're asking them to do and how we're compensating them for their actions.

So, part of what I would say is how have we done? As a third-party aggregator, we've seen a lot of change in the demand response market over the years. We've obviously made a lot of progress recently in terms of integration into the wholesale market.

But as Barbara indicated, there are a lot of complexities associated with that.

And in terms of actual DR participation, we've seen a fairly significant decline in the number of customers that are participating. And I think this issue of alignment is a major cause for that.

We've changed market rules. We've changed the way the resources are utilized. But we are not always communicating value and need to the customers, so that they understand what we're asking them to do.

And as far as third-party aggregators and adjusting business practices, we're not always given enough foresight into what changes are coming down the pike and how quickly we can implement them.

It has been our experience, in California, that these programs are the most costly programs that EnerNOC operates across the world. And part of that reason is because of frequent rule changes and need to re-paper customers, go out and re-contract with customers, and that's all very expensive when rules are changing very frequently.

MS. KEATING: I guess I would echo what both Mona and Barbara just shared. And I acknowledge the slide that Bruce showed earlier, it really did not show growth in megawatts, per se.

I think at Edison our efforts for the last few years have been focused on integrating all of the megawatts that we had in to the market. And so, we've had a team of folks concentrating on that and it has been really challenging.

I can imagine how challenging it has probably been for third-party aggregators, who hadn't had to deal with that situation, yet. I can say it was certainly challenging for people in our operations team, on the trade floor, who work with the Cal-ISO every day. It's been challenging for them to figure out how to do it and how to present those resources to the ISO accurately. And I'm sure, I know it's been challenging for Jill and her team, too.

So, I don't want to, well, take away from the accomplishment of DRAM. I think, you know, we just closed the third RFO in the DRAM pilot and that is a success story. I think Mona shows it more clearly on slide nine of -- I believe it's slide nine of this deck, how the megawatts have grown over time. So, I would give aggregators a lot of credit for getting into that space.

Being a participant in the wholesale market is extremely, I think, challenging when you're a new entrant.

So, there is progress there because I think in some of Mona's other slides she does show some decline overall in enrollment. So, it's kind of good and bad.

We've made a lot of headway with respect to integrating our portfolio at Edison, but there's been a lot of challenges along the way and there's still room for improvement.

MR. FINE: Hi, thanks. So, thanks for starting with the question of kind of what have we accomplished recently. It's worth taking stock.

And when I think back on how long I've known the folks I'm sharing this panel with, I realize we've actually made an enormous amount of progress.

When I started thinking and working on DR, we were all still trying to understand what each other was talking about. Over time, we've actually worked closely together. I've spent time in PG&E's offices, in the Load Modifying Demand Response Working Group for well over a year. I've spent time in other working groups.

And one of the reasons you haven't seen me, now, related to time-of-use rate deployment and related to distribution resources planning, where we've refined the language and the description of the problem in those settings, as I well I think four out of the five panelists here were technical advisors on the LBNL DR Potential Study you just heard presented.

So, over time I think we really have clarified our language. I think we generally agree on what a lot of the challenges and problems are. What you'll hear today is an enormous amount of growing experience in the market side of DR and the experience that the operators are having with high transactional costs and regulatory uncertainty.

But what you'll also hear is that in defining our language and focusing what the problems are, we've expanded the definition of demand response. We've expanded the definition, as you put it, Commissioner McAllister, to the notion of smart management through DR and EE.

The other thing that's happened along the way is we've had enormous success with our renewables. We have seen renewables boom and that's created this pressing problem we have now, which is we're actively curtailing renewables to a large extent. We have made great progress in recognizing the role that time-of-us rates lay in that, and I'll get into some of the barriers and challenges associated with that.

But we have seen real change and growing need for DR, and not just the traditional DR, but the new load-modifying type of DR that we're planning for here.

And, you know, we're also seeing routine negative prices in our wholesale markets now. And I'll just note that at the same time we're seeing that and everyone has learned to understand and focus in on the duck chart, there also is a distraction away from the fact that load is still large in the middle of the day, and it's still a wonderful opportunity to align load with our solar resources. But there seems to be, at times, a preoccupation with wholesale prices and the perception that negative prices means negative value for resources and, in fact, can be very valuable.

So, I think that's part of our understanding of the problem and agreeing on what those challenges are, and also just refining our language. So, I'll leave it at that for now.

MR. HUNGERFORD: All right, thank you. Let's move on to the second question which is, I think, what all of you are a little more excited about. And that is can you talk to us a little bit about what kind of barriers to expanding DR participation, and expanding demand response as a resource in the State, that we're facing?

What's going on in the institutions, the regulatory constructs and in technologies, if we need to talk about that that are currently inhibiting expansion of DR participation?

We could do that if you'd like to, we could start with Barbara.

MS. BARKOVICH: I'm always willing to go first. Well, I mean you have my slides and I think you're going to hear a commonality of theme on a number of the integration issues. But I think a couple of the biggest have to do with, one, the resource definition.

That is, if you're talking about something that is going to be integrated in the CAISO market, and I also think there are issues for things that are not integrated into the CAISO market.

But certainly from an integration perspective there is a definition of what constitutes a resource that you're going to hear from us, that is creating some real challenges. I'm not saying the definition was created for a bad reasons, it just has consequences.

And that is that each resource has to represent customers served by one load-serving entity, one demand response provider, it has to be within sub-load aggregation point, and has to be at least 100 kilowatts.

Now, as Edison has discovered and Erica will speak to this, when you try to aggregate your existing resources to meet t hose criteria, and we do nowadays -- I mean, you can say, well, we have utility programs, so the utilities, the demand response provider. But, obviously, now we have non-utility demand response providers. And we have multiple load-serving entities. It's no longer the utilities anymore.

We have community choice aggregators. We have electricity service providers out there. Okay. We have Sub-LAPS whose definitions recently changed to correctly align them with the local capacity areas.

But that means if you take an existing set of resources, you have to parse them into different parcels in order to be able to get them to fit. And they have to be at least 100 kW in order to be visible to the California ISO.

All right, so you try to do that and then what happens? You have a perfectly good resource, and then 30 kilowatts move to a CCA. All of the sudden your resource doesn't mean the minimum requirement. Okay, I mean that's just the way it is.

You have somebody who's participating in a utility program and now they want to do DRAM. Well, all of the sudden they've got a different demand response provider.

So, in trying to take existing resources and put them into the market, and this would apply to aggregators as well of existing programs, you have a number of different variables which shift over time. So, you've got resources in and out of the market. As part of the demand response registration system you have -- you're registering all those individual customers. If a customer leaves, you know, you basically have to revise the aggregation so you get the location correct.

So, these are the kinds of things that make demand response more challenging than a power plant that doesn't move its location, doesn't change its output unless it's got a -- you know, it's upgraded or it's got a D rate (phonetic), right. It doesn't change Sub-LAPS. I mean, it's just kind of there, okay.

So, what we've discovered is when you're dealing with distributed resources, like demand response, and it's true of other types of DERs, it's just that some of the locations are pretty darn small for demand response, trying to meet those requirements has proven to be challenging.

And I think everybody is grappling with that in a situation where for a customer of a CCA or an ESP to participate in a demand response resource, they're load-serving entity actually has to sign off on their participation, which can create lags. I mean, that's one of the requirements.

So, trying to deal with a resource definition that exists for a reason, I mean if you had one customer and two demand response providers, and they were both getting in at the same time, and you wouldn't know how to settle it. It's not to say there aren't reasons for these rules, it's just that it makes it complicated to make it all work and not have resources potentially going in and out of the market. That, I think, is an issue that all of us share as a concern.

And another one I wanted to mention, and then I will leave things like settlement baselines to others, because they've addressed them, but one that I particularly wanted to focus on is the telemetry issue. Because this is an issue that was specifically called out in the 2013 IEPR. Okay.

So, what's happened on telemetry? Well, unfortunately, not as much as we would have liked. The CAISO has loosened up some of the rules, but the requirements are still as follows. You require telemetry if you are in the energy market and you're over 10 kW, okay. Telemetry right now is expensive. There are ways -- there's research on making it cheaper that I will allude to, but it's expensive.

So, what do you do, you've got a 300 megawatt program and you don't want to promote on telemetry, you break it into 31 little resources so they're each less than 10 megawatts. That means you have to manage, you know, 10 times, or 30 times, or whatever as many resources, depending on what the program is.

So, now, you're bidding it in and you've got to have bid prices and you've got to have a bidding strategy for every single one of those resources. And remember, they have to be co-located geographically.

So that the telemetry requirement has actually ended up creating more operational difficulty for DRPs because they wanted to under that 10-megawatt requirement.

Now, the CAISO did in fact relax the rules for non-spin. It used to be there was a one minute requirement for non-spin, and now there's a five-minute requirement which is good, although it still has to meet the plus or minus 2 percent accuracy requirement.

So then that's good. Now, we have to find the technology that will allow us to do that so that we can meet the five-minute requirement. And if it’s going to provide spinning reserve or regulation it still has to meet the four-second requirement.

What does that mean? Okay, well, how can we find a cheaper form of telemetry? The traditional form of telemetry is in the ten figures. So, there’s been a lot of discussion about using advanced metering infrastructure in order to be able to provide data that can be aggregated for telemetry. Now, that’s been the holy grail for years, but it’s actually only recently that people have started to do research on how to do that.

And I cite in my slide deck a study that was recently done. And I believe that through EPIC funding the Energy Commission is supporting other research to try to figure out whether you can take data from advanced meters, you can push it through a gateway, okay, using something like Zigbee. A gateway, like the home energy network, you can then send it off to a cloud, aggregate it, send it to a RIG, which is a Remote Intelligent Gateway. And the Remote Intelligent Gateway is what talks to the CAISO, okay, through the scheduling coordinator.

So, if you can do that and you can find a way to aggregate the meter data, that would take advantage of a technology that already exists in some, but not all smart meters. Large customer meters don't have hands, okay. They don't have that capability.

The smaller customer meters, the most recent ones do, so that's good.

So, now we have to find a way to do this. There have been experiments. We have to find a way to scale it up, okay, make it work efficiently; work out all of the bugs, which is not going to happen overnight. But I mean it's exciting as a way of being able to aggregate a lot of small resources into something, for example, that could provide regulation.

Another potential is that because the CAISO has approved the use of statistical sampling, if you've got a bunch of residential customers maybe you don't even have to get telemetry from all of them. Assuming you have enough uniformity in your sample size, you might be able to take every tenth, or what have you.

So, if this scales up, it's going to be really possible. But it is not going to happen overnight. There's still a lot of work that has to be done.

And the other thing is that the existing technology, the work that's been done so far using meters you cannot provide four-second data. You can provide one-minute data, you can provide five-minute data, but so far nobody has found a way to provide four-second data for something like regulation.

And I know that there's been a lot of interest in taking -- or even for load following potentially, right? I mean, and taking lots and lots of small customers so you could create a ramp that provided flexibility.

So, I've been talking too long, but I knew telemetry was specifically called out and I wanted to mention it.

There is some real potential here. I think we've made a lot of progress in the last couple of years, but it's not going to happen overnight. And we need to scale up the existing research to prove it out and we need to come up with an alternative solution, apparently, for four-second data.

So, thank you for indulging me and talking too much.

MS. TIERNEY-LLOYD: Thank you. I'm going to start in talking about what I think barriers are for demand response relative to the complexity of providing the service. So, because EnerNOC provides services in many parts of North America and around the world, we've seen a lot of different market structures.

Starting with the ability to be able to dispatch on a system level. In PJM, for example, system resources can be dispatched and aggregators can have a portfolio that spans the system. And then when the resource is needed for local reliability it can be dispatched at the local level, as well.

The California market structure starts off with a very local dispatch and you don't have the ability to aggregate that up across a larger area, such as a default LAP, or the utility service territory, or the system at large. So, we start with Sub-LAP and that's the only basis upon which demand response can be aggregated.

And as Barbara indicated, as you get to smaller and smaller local specificity your aggregation is smaller. It requires greater management. You have to then break it up by load-serving entity. So, you're pulling apart a resource, the value of which comes from aggregating many different types of customers into smaller and smaller resources, with higher risk of performance. And by doing that, that increases the cost of providing the resource.

So that, in addition to decreasing the notification time, the advanced notification time for the resource to be dispatched is also another way of increasing costs of providing the service. Because as you get to smaller notification times, you have to move into automation and automation costs money. And there are also certain customers that will never allow you to automate their facilities because of safety and their production concerns.

So that when you move in that direction, you're also culling the number of resources that can and are willing to participate in that kind of service.

Number of dispatches is also something that we've done, we've tested to make sure that demand response can be dispatched frequently. But I don't know that we're correlating a value with frequent dispatch. There's not really a value for frequent dispatch in our cost effectiveness methodology. There's a value for availability, but not frequent dispatch.

And if we can't provide a correlation between why a customer is being frequently dispatched, other than to test the capability, but it isn't directly related to a need on the grid, prices, reliability, something of that extent.

And since we serve in the commercial/industrial sector, we have plenty of very savvy customers that will go to the Cal-ISO website and find out what's happening on the grid and ask the questions about why they were being dispatched. And that creates customer dissatisfaction.

We have a lot of customers that are very willing to provide reliability services for the grid, but have businesses that they're running. And if they can't understand the reason for the dispatch, they become dissatisfied.

Resource adequacy is the primary economic driver for demand response. And so, it's very important to understand the rules for resource adequacy because it's basically a capacity resource. It's not dispatched for energy purposes, primarily.

You know, we're talking about shift, which the discussion was around providing energy compensation for that resource, but that's not been what's been driving demand response to date.

So, having coordination between Cal-ISO and what they see as reliability issues and requirements for the resource, and the CPUC in terms of their resource adequacy requirements is really important.

We've had a few incongruities in some of those rules come up over the past year, and that creates a great deal of market uncertainty because what happens is those differences show up in contracts for third-parties, and it's unclear whose rules you're supposed to be following. So, that's important as well.

And we've had in the past fairly onerous penalty structures on demand response resources. And it's been a little bit more of a stick, than a carrot, in terms of encouraging customer participation.

I think Erica has a slide that shows that depending upon which baseline you're using, you could have very vast differences in the amount of performance that's accredited to that customer.

We've had several customers that have been able to drop megawatts of capacity and gotten zero recognition for that because of baseline and measurement reasons. And if you're going to go to that level of effort to reduce a megawatt of capacity and you get zero compensation for it, that's not a good recipe for customer satisfaction.

Those are the primary points that I wanted to make.

MS. KEATING: Do you have the presentation in front of you?

MR. HUNGERFORD: Which slide?

MS. KEATING: I was going to go, just building on what Mona was just talking about to give you the visual, slide 15 actually shows the issue with the current baseline methodology.

And as Ms. Powers talked about earlier today, the ESDER Phase 2 working group did complete that Phase 2 recommendation. I believe it was approved at the CAISO Board to adopt a more appropriate baseline for residential demand response resources. However, that still has to go to FERC, obviously, and then it still has to be implemented.

So, we're still looking at months before we actually see that in practice. And in the meantime there has been a lot of conversation about this particular issue lately. As you may be aware, there's a DR application going on for the investor-owned utilities.

So, this graphic shows what Mona was just referring to. The red line at the top, that is meter data coming off of this RDRR resource. This is an Edison Summer Discount Plan resource.

That bottom blue line is the 10&10 baseline, as calculated per the current rules. And so you see the load reduction there, it was great. This was on June 20th of last year.

Unfortunately, it never goes -- it never crosses under that blue line because of the baseline. And so, it's not only that your customer isn't getting paid for the load drop, but in this instance this unit would owe money back to the CAISO per current tariff rules.

So, it's a big problem. And so we have a lot of work to do. I think everyone in this -- everyone in demand response has a lot of work to do right now to, number one just clear up all of these things that still need to be made to work for everyone. Just all the market rules at the base level.

And then there are, I think, and I've heard the word used a few times, and it's very important, but the term "value". Demand response gets all of its value, as Mona said, from resource adequacy capacity value. And we've been grappling with this internally, at SCE. I don't that there is -- I don't think we're all convinced that that is the single and only correct source of value for these resources. There has to be another sort of value.

I've heard, but I'm not involved in the IRP proceeding, that there is an effort to try to establish some sort of a qualitative value for these kinds of resources, maybe. I think Edison would also be extremely interested in trying to figure out if there's a distribution level value that could be used because we do rely on these resources at the distribution level.

Edison has had its reliability resources in its portfolio since the 1980s. And our transmission and distribution staff has used the locally, for many, many years, to correct imbalances happening at that local level, whether it’s from equipment overload, car runs into a piece of equipment.

Most recently, some fires up in the San Bernardino Mountains caused us to call a local event. So, the value questions is extremely, extremely important to focus on for the future.

CHAIR WEISENMILLER: Yeah, I was going to ask -- I know we have some questions on this specific topic, but I wanted to make sure everyone at least got something in before we jumped.

MR. FINE: Okay, sure. So, the theme here is you’re going to hear comments on supply DR from my three fellow panelists, and I’m going to comment on load-modifying DR. So, if you wanted to make a quick -- okay.

And so, as I said earlier, there’s broad agreement, I think, in the industry about what some of the challenges are. You’ve heard the need to link a resource adequacy value to DR.

I’m going to back up a little bit, again, focusing on load-modifying DR. I want to bring to your attention, in our presentation, I have a couple of slide sin there showing you the magnitude of curtailment and the prevalence of negative pricing in wholesale markets.

And if you'll go to slide 25, you'll actually see a slide from the Lawrence Berkeley Lab's DR Potential Study.

I'm bringing that slide to your attention because it reveals the real opportunity to save customers money by using more load-modifying Dr.

In Bruce's presentation, he provided a definition of -- where did it go? I have too many papers here. Of the goal. And the third piece of the goal was to enable customers to control their energy bills.

And a key piece to doing that is pricing with retail rates, incentives, and hopefully education around opportunities related to distributed energy resources.

So, if you look at this slide from LBNL, what you'll see is the potential for making better use of our utility-scale renewables and rooftop solar can be dramatically increased by shifting demand.

And this slide here shows that if we don't achieve a demand shift in year 2020, to meet RPS goals we're going to over-build our renewables so much we'll be dumping 12 percent of their capacity. If in fact you can effect a 20 percent load shift of demand to line up with those renewables, and that's the sun in the middle of the day, you can increase the utilization rate of those renewables six fold. That is, instead of dumping 12 percent, you only dump 2 percent.

And that equates to a savings in California of $700 million per year. And just to put that in perspective, that's about $60 per customer today.

Now, in the context of time-of-use rates, as we're trying to move customers through pilots of -- residential customers at time-of-use rates, we're trying to avoid bill impact in a month on the order of $5 or $10 per customer. We think those bill impacts actually will be reclaimed in the wintertime by better falling cost causation. We're trying to avoid $5 and $10 bill impacts in the summertime. And at the same time we're missing, if we're not doing a good load shift, an opportunity to capture massive savings in the system.

Slide 26 shows you the rates that the IOUs are testing in the residential time-of-use pilots. And what you'll see there is no price signal in the middle of the day that reflects the negative prices that we're actually experiencing. And what we're seeing here is still, obviously, folding in TND costs into the picture.

So, if you want to incent customers to shift demand, you need to be doing more than just these relatively non-price-signaling time-of-use rates. EDF has supported the idea of the incentives, and those incentives can be informed by the work that we're doing, for example, in the distribution resources planning proceeding.

I won't go into the slide I have now that talks about the process solution to better link to various utility programs, but that is a key barrier we're facing now. And a lot of that, in my opinion, boils down to what the utility incentive systems are, what their business models are, and opportunities that aren't really there at this point to really help empower customers to make better use of distributed energy resources.

So, you actually can see examples of kind of more exciting rates. San Diego Gas & Electric has proposed a third rate to test that is a big spicier, and even proposed it to provide a bill credit for energy used during negative price times of the day, in the wholesale market. But it's a very small piece of the overall TOU piloting regime. And the other IOUs are not testing a similar rate.

I will also note that SDG&E is testing this rate into vehicle grid integration pilot, as well. We know we need to get EVs to take energy in the middle of the day as part of the solution to making better use of renewables. We don't yet have robust price signals or other strategies to get utilities to do that.

We are investing in the infrastructure, but it remains to be seen whether or not that infrastructure is going to be used and useful in terms of taking renewables.

Commissioner McAllister, you made the point that we are going to over-invest in infrastructure and that is the primary concern that I see right now.

I mentioned I've been in the working groups for distribution resources planning and time-of-use pilots. I cannot cover grid modernization, but I tell you that's where price is going up and it's going up fast. And the primary motivation of grid modernization is to host EVs, and rooftop solar, and other DERs. And what's not happening is a plan to legitimately optimize those resources.

And the consequence is going to be massive price pressure. And those who are going to be paying those prices are those who aren't investing in DERs. The people driving the Tesla's are self-generating with their rooftop solar. The people with high energy burdens in the Central Valley don't have these resources and these are the ones who are going to be paying the higher grid prices. That's a lineup that we cannot accept and allow to play out, now.

And that’s one reason EDF is actually, even though we’re very bullish on residential time-of-use rates, we’ve actually protested the current plans of the IOUs.

In 2019, they’re going to default to half a million California customers at time-of-use rates, and we don’t think the plan’s ready for that, yet.

We think there are a lot of exciting solutions related to DERs, including demand response, but we don’t see the motivation in that setting to utilize those resources as robustly as we think they can be used.

So, I’ll leave it at that for now, thanks.

CHAIR WEISENMILLER: Let me ask a follow-up question for you. Probably, the last Commissioner at the Energy Commission who was really passionate on demand response, apologies to Andrew, was the late great Chair Pfannenstiel.

And one of the things that she did was to look at the Energy Commission’s Load Management Standard authority. We had load management standards the first time I was here. The question in part was cost effectiveness, you know. It appeared many people were signing up for air conditioner cycling where you had both -- you know, both individuals out working during the day and collecting their check back for giving the utility flexibility over their air conditioner.

So, basically, I think all of the load management stuff we did at that point eventually faded. But again, is there something we should be doing -- and when Jackie was looking at, again, trying to revitalize demand response when she was Chair, obviously one of the things she was looking at was rate design.

But again, just a really comprehensive set of trying to figure out what can we do from a load management perspective.

So certainly now, or in your written comments, we'd love to see if anyone thinks we can do anything useful there.

MR. FINE: Yeah, I'm not sure I heard the question in that. I will just point out that Mary Ann's presentation, in terms of whether there's value, you know, there's massive value in shift DR.

CHAIR WEISENMILLER: Right.

MR. FINE: -- and shape DR. That's very cost effective for even at zero cost.

I think one of the other challenges is that our tradition of DR is to look at the cost effectiveness from a supply and control perspective. And what we're really talking about now, I've heard CAISO colleagues say 80 percent of the DR in the future is going to be on the customer side and it’s not going to be something that we see or count.

And actually, I do want to bring -- thank you for asking the question because I do want to bring my comments back to the IEPR.

CHAIR WEISENMILLER: Right.

MR. FINE: Which is this load-modifying thing DR, we say we know it has value for resource adequacy and we know it will show up in the IEPR eventually. The problem is there’s a bit time disconnect there between that resource showing up in the IEPR and us avoiding building other resources to provide those services.

And similarly, the IEPR, what it really does traditionally is reflect what other policies and programs are creating, but it doesn’t guide those policies and programs. But in fact we could use the IEPR in a different direction.

For example, the IEPR does produce a various set of demand forecasts based on your assumptions around energy efficiency. Yet, when we take the IEPR demand forecast into the RA assessment, we take the mid-case value which truncates the value that energy efficiency and DR, as Commissioner McAllister rightly pointed out, are tightly integrated. It cuts that potential resource out of the picture of providing resource adequacy.

The other time disconnect is if you use the IEPR to recognize in a high energy efficiency, a high DR scenario in the future, we could avoid the one or two percent peaker plants that Commissioner Guzman pointed out.

Again, we don't use the IEPR to guide us to policy to achieve those realities into a high energy efficiency, high demand response. We just ask could it get there?

CHAIR WEISENMILLER: But again, to push you back. I mean when San Onofre went down, when Aliso Canyon went down, all three of us called for enhanced demand response, right? I mean, that was at the top of my list. You look at the numbers and my, God, you know, it's not sort of an astounding response to that call for action. You know, I think there's a lot of preparation now.

But again, this stuff has to go real fast, you know, to get into the forecast. And, you know, at least the current trajectory doesn't make me very comfortable that it's getting real fast.

MR. FINE: Yeah, so thank you for that. If I may, Mary Ann, in her presentation, it was one of her early slides where she showed the time differences in the different types of DR resources. It's her seventh slide.

And so, another place where I've been spending my time is the IDER pilot --

CHAIR WEISENMILLER: Right.

MR. FINE: -- the idea of incenting utilities to use distributed energy resources to solve distribution system needs.

Again, thinking about this time issue that you're pointing out, right, when you have a situation on the grid where you've got a problem, either due to DERs, or some other problem, the notion of using price signaling to help the grid, you know, the customers and DRs to evolve to solve this pressing problem is a disconnect in time, right.

On the other hand, if you look at the rest of the grid where you don't have a problem today, we could be asking how do we use pricing to incent health DERs to evolve on the grid to avoid some of these distribution system costs that we're facing in areas where we haven't evolved smart DERs.

CHAIR WEISENMILLER: Right.

MR. FINE: So, with the business model problem, there isn't a lot of incentive to make that evolution happen yet, right. So, 98 percent of the grid doesn't have problems now. How do we use pricing to incent

DERs, including demand response, to enhance the ability for that part of the grid to host more DERs and to avoid other types of distribution system investments? That's a big piece of the question that we're not asking, yet.

COMMISSIONER MCALLISTER: So, I want to also just sort of kind of put a different spin on that. I mean right now we have an opportunity to get this right when the stakes are relatively low and we're kind of long on resources and we don't have these -- you know, most of the grid is fine.

But, you know, some years' time down the road we're not going to be in that situation and that's actually going to be by design. Because, hopefully, we're going to have optimized, and we're going to have retired, and we're going to have replaced judiciously with new, cleaner resources, right.

So, at that point I really want to be in a situation where we could dispatch, you know, these kinds of resources, DERs and certainly demand response at that -- in the right amounts, and in the right way, and at a very low transaction cost. In a kind of automated, you know, hunky dory kind of way that customers like and sign onto. So, that's the goal, I think.

I guess, so I was going to bring up load management standards, too, and I guess ask about standards slightly more generally. You know, that's an area where we have a lot of authority. And the problem with some of these types -- well, with demand response, let's just say just specifically is requiring it needs a value proposition to justify it as cost effective. That's our mandate.

And so, when we don't have the price signals we can't do that analysis because there isn't a cost effectiveness argument that's good.

So, load management standards is a place where, you know, I think in the Chair's and my opinion we have under-utilized our authority. We have strong authority, based on the Warren-Alquist Act. Alongside, you know, appliance standards and building standards.

And all three of those could come into play here to solve this problem, but we have to be careful. You know, that's a big lift, it's a big regulatory process and it takes time.

And so, I would really appreciate some thought about that in your ongoing interaction, certainly your public comments. Because we could sort of -- hopefully, it's a round peg in a round hole, right. But we can do that, and I think are willing to do that, but it has to be a very clear goal and a clear kind of a proposition. A clear problem that we're trying to solve and that that works. So, I would really appreciate your thoughts on that.

We're going to have some entities, some panelists in the afternoon that are going to talk about the customer side a little bit more. I mean, Mona, you did a lot of that. But they're doing sort of different ways of working with customers behind the meter.

I guess I'm interested in your understanding, this panel's understanding, and not everybody has to answer this, you know, if you don't want to, but that disconnect between sort of the daily load shape and the average calculated load shape on which the demand response is gauged as a success or not a success, and if they've been paid for. I think, Erica, you pointed that out.

You know, are we seeing customer -- so that's a problem. It's obviously a concern. I mean, we want real load when it's there, when we need it, right. So, are you seeing customers kind of manage their demand in an artificial way in order to sort of protect themselves against, you know, possibly being called? I mean, I guess how much of a distortion is this, really, in terms of customer behavior?

MS. BARKOVICH: Well, I'll start. This is Barbara. I'll start out by saying that what Erica was referring to is the fact that we're measuring demand response against a counter-factual, right, which is the baseline.

COMMISSIONER MCALLISTER: Yeah, right.

MS. BARKOVICH: And the current baseline we have works for certain kinds of loads and it doesn't work for other kinds of loads. And the kind of load where we're having the greatest amount of difficulty is weather-sensitive load.

This is the reason there's been an argument made for, and we're not there yet, one, having different baselines that are, for example, rather than day matching, weather-matching baselines that would try to take into account that variable. That they've been proposed and they're working their way through the process.

Another difficulty we have, though, is if you take those resources and you integrate them into the California ISO market, the resource data template -- now, I'm going to go nerd on you. The resource data template has a problem with the fact that it establishes a PMAX, which is the maximum output for the resource that is not supposed to be de-rated. And so, you can get -- on a hot day, let's just say your resource is 8 megawatts on a hot day, okay. Well, on a cool day you can't go in and say the temperature's only 80 degrees, it's not 100 degrees, and so on a cool day I can only give you four and a half megawatts.

Instead, you get a penalty because of the fact that your resource value is lower, which is the function of weather. And we have yet to come up with a solution for dealing with how to integrate weather-sensitive resources into the market and not have them be penalized unintentionally, you know, by the market, and then at the same time capture the actual load drop that Erica was dropped about because the current baselines also under-represent the load drops.

COMMISSIONER MCALLISTER: Yeah, yeah.

MS. BARKOVICH: We've really got two issues here. We have a measurement and settlement issue and then we have a penalty issue.

So, there are situations like that where we still have a number of different levels of problems we need to deal with.

And what you're saying is what is the customer doing? The customer in this stuff I think is just confused.

COMMISSIONER MCALLISTER: Yeah.

MS. BARKOVICH: Because the customer is saying you asked me to shed my load. I shed my load, I did what I was told. It's not my fault that the 10-in-10 baseline, as opposed to 3-in-5 weather baseline didn't capture that load drop.

And then the aggregator or the utility is going, wait a minute, I delivered all the megawatts I could deliver, the PMAX and the resource data file is, you know, 8 megawatts for this resource, but it's only 80 degrees outside, so I only got four and a half. So, now, I'm having to pay the CAISO, rather than the CAISO paying me, so I can pay my customer.

COMMISSIONER MCALLISTER: So, thanks, I think --

MS. BARKOVICH: That's probably more than you wanted to. But anyway, well, this is the kind of thing we have to deal with.

COMMISSIONER MCALLISTER: Yeah, I'm just looking at the clock. I really appreciate it.

I mean, I guess, this is like the classic example of a program design that doesn't work for customers and I think we need to think about that.

But I'm tempted to ask about rates, we're going to talk about that in the afternoon. But anyway, thanks for that.

CHAIR WEISENMILLER: I was going to say, I think at this time we're going to break at 12:45, so I'm going to have David do rapid rounds on the next two points.

MR. HUNGERFORD: You read my mind. So, that's why you're the Chair.

Erica, I'd like to start with you and I'd like to combine these last two questions. Can you give me a quick answer on what you think are the most important things that we should focus on in the short term and in the long term for DR?

MS. KEATING: Sure, and I'll try to be quickly. In the short term, as I stated, just getting, trying to write the rules that we have right now. Trying to write the rules both from the resource adequacy proceeding perspective and then from a CAISO tariff market design perspective. That's a high priority just to right the portfolios that are in to date, let alone adding tomorrow.

For the future, there's a couple of slides and you can read them at your leisure, slides 16 and 17, where I've provided some information here on CCAs, and the potential that they pose for us in the future. You may or may not familiar with the cost causation, competitive neutrality principle, which says that once a direct access or community choice provider implements its own demand response program, the competing utility shall, no later than one year following the implementation of that program, one, end cost recovery from that provider's customers for any similar program. And, two, cease providing the similar program to that provider's customers.

So, this is really going to obviously cause some chaos in the market. As Barbara gave some great examples earlier about, you know, you add another LSE, customers start switching. And then, there's a bunch of operational market things that we have to deal with.

But for the CEC and the CPUC who are interested in potentially establishing demand response goals, trying to figure out which entities are going to be impacted by fulfilling those goals that's a big concern. That's one for the IOUs and for Edison, in particular.

You know, whether it's the IOUs that would be bringing those megawatts or some other entity, I think we're open to wherever those decisions lead. We're just interested in making sure that the procurement mandate is doable and that the costs are distributed accordingly, and that they're not all borne by one group or another, regardless of load-serving entity.

So, you know, there's this big I think shift happening in the immediate 5- to 10-year future about who is actually going to be providing retail energy in the State. And so I think that's actually, that along with the value proposition, those are two really big fundamental questions for this group to think about.

MR. HUNGERFORD: Mona, would you like to go next?

MS. TIERNEY-LLOYD: So, I would say one of the big priorities is figuring out where do we go with DRAM from here and moving that into a permanent program as quickly as possible.

There is some conflicting points of view about whether we should have a stand-alone DR requirement or whether everything should be folded into some kind of all-source RFO through the IRP. So, getting an understanding of how DR procurement is going to happen into the future is really important.

Completing the data access work that has begun with the Energy Division, and getting that implemented so that more and more people can get customer information as quickly as possible, with as few interferences and time delays as possible is really important.

Implementing the baselines that Jill spoke about, to give customers more options to measure their performance, and then bringing that down to the retail level, too, for the utility programs I think is also important.

And then, considering how baselines are going to evolve as we try to address the duck and shift the load from the evening hours into the middle of the day. How do we acknowledge increases in consumption from customers that's there to provide grid reliability, and reduce the neck of the duck in the evening, and provide value for both of those results.

And then going forward, the issues -- the amount, the scale of participation that could occur in the wholesale market through residential participation is huge. So, being able to accommodate not only residential participation, but DER participation in the wholesale market is going to be a very large challenge.

And then, the integration of what happens on the distribution grid and the transmission grid, I think, is going to be a longer-term challenge. And, you know, how you determine the primacy between if the utility needs the resource and the wholesale market needs the resource there are efficiencies to be gained by that coordination, but there's also some issues about who gets to use it when it's needed, in either instance. Thank you.

MR. HUNGERFORD: Jamie?

MR. FINE: Well, again, thinking about load-modifying DR and the challenges that we've seen in that, and opportunities we've seen in that context, the big issue here is that modernity for the grid needs to be achieved not at the cost of environmental justice. We need to achieve affordability through connectivity. And we need to, rather than conclude that someone folks aren't prepared to respond to time-of-use rates, we need to ask the questions how do we position these households to be responsive to time-of-use rates?

And this includes investing in distributed energy resources that includes load-modifying demand response.

And at this point, our investor-owned utilities have a really good idea of which households are going to do well with time-of-use rates. And the analogy offer is that as the doctor, they could tell their patient right away whether or not you have high blood pressure. And what's not happening is a recommendation about diet and exercise. How do we help get healthy?

There is a resistance to talking about rooftop solar, to demand response, to energy efficiency, anything beyond how it serves the requirements of the utility energy efficiency programs. And we need to break that. We need to provide real sugar for the utilities to optimize DERs and really help customers be price responsive.

The solution others have offered is don't provide time-of-use rates to our most at-risk households. And what you're doing is you're cutting off the low price time of the day to use electricity, and you're undercutting the value for energy efficiency, and load shifting, and eventually opportunities like community solar and community EVs.

And I'll mention that we have a ways to go because even right now commercial small businesses, in the Central Valley, you've seen my stats, you've heard it said about curtailment and negative prices. Right now, the peak price time for a small business in the Central Valley is 1:00 to 5:00 p.m., exactly the wrong time it should be.

So, we have a ways to go to line up the rates with the real opportunity there and then we need to help close the marketing, education, and outreach gap by once you provide that value proposition with rates and incentives to really mobilize the DER industry to deliver those solutions.

You know, it wasn't our investor-owned utilities who taught customers about rooftop solar, it was the solar companies. Thanks.

MR. HUNGERFORD: Go ahead, Barbara.

MS. BARKOVICH: I will make three brief points. One is the Commission is working on changing time-of-use periods. And one of the DER industries is the most resistant to making that change.

Number two, I think one thing we haven't fully discussed here, but it is important, is for that demand response that cannot be integrated into the CAISO market, the issue of appropriately reflecting it in the load forecast is an issue. Because it doesn't mean it's not happening, it just means it's not integrated.

And there was a working group that Jaime referred to previously, that kind of stalemated on that issue. But how to appropriately, other than CPP rates, and now they're beginning on time-of-use rates, how to reflect the impact of load-modifying demand response in the load forecast that is being used for resource planning purposes is an important issue.

And lastly, because I represent industrial customers, I would like to say that one of the reasons industrial customers participated in demand response is because electricity is very expensive in California. And so, participating in DR gives them an opportunity to help with the grid and also save some money, so they can stay in business.

If we come up with some super sophisticated, fancy, whiz, bang DR that they can't participate in, because they can't adjust their load every five seconds, and they can't participate in DR that is not going to help them stay in the State of California, where they are subject to cap and trade, and could move elsewhere where there could actually be worse consequences for climate.

So, when we're thinking about demand response of the future, let's also try to come up with demand response that everybody can participate in, who wants to, so we get the greatest buy in and, you know, retain those customers in the State. Thank you.

MR. HUNGERFORD: Final questions?

CHAIR WEISENMILLER: Any final questions or comments? Keith?

MR. CASEY: Well, first off, I think it was an excellent panel and I fully appreciate the implementation challenges you're raising. It's hard. It's hard for you guys, it's hard for us, and we're grinding through it. But I think it's absolutely essential that if we're going to evolve to the grid of the future, DR's got to be integrated as a major resource in our market. And you guys are working through the heavy lifting to help that.

I think with regard to some of the specific issues, in the interest of time I won't get into them, but I think just one I'll mention. And Barbara, on the

1 LSE per resource, I don't think that's sustainable. As you mentioned, with CCAs and the like. We've got to find a way to overcome that. So, I look forward to working with you on that. And grinding through the telemetry, as well.

The last thing I'll just say is when we think of DR, you know, I heard a couple of panelists, and even previous speakers say, well, we need to know what is expected of a DR resource and get clarity on the rules.

I think what we should think of is what are the services a DR resource can provide and give them optionality on the level of difficulty or suitability of providing those different services? So, it's not a one-size-fits-all, if you're a DR, you have to do all of this.

To Barbara's point on some of these industrial customers, maybe there's just a base service they can continue to provide that has value to the grid, but we can rely on other types of DR resources to provide some of the more frequent dispatching integration services that we need.

So, just a great panel and really appreciate your candor.

CPUC COMMISSIONER GUZMAN ACEVES: I wonder if you guys have given any thought, it sounds like you all have a lot of experience, collectively, over the years of structure for working groups that have worked? And just kind of, maybe, on the social engineering of some of these policies, if you've thought through at all a new or old method by which our efforts and coordination could really be more expeditious?

Because none of these issues sound like fundamental disagreements. It just really takes a lot of time to get people in the room and get things hashed out.

Is there, and you can think about this, but does anything come to mind now, or later on, how to do this in a timely way? And you all, you know, collectively, in just your last minutes here talked about a dozen issues.

And I think there's clearly interest of all of our boards and commissions to figure this out. But do you have any thoughts on the more practical side of how to do it?

I know we'd like to do really not-expeditious processes. I don't think you want evidentiary hearings for all of this.

CHAIR WEISENMILLER: I don't know. Well, I was going to just remind people, I think the last time your Commission, en masse dealt with -- I just remember one

Commissioner, they were less patient than you, even. So, they were saying, they were talking about programs which took longer than it took the U.S. to mobilize World War II to get to the next stage. So, hopefully, we can move expeditiously.

Because again, you know, we've all been in these places, Aliso Canyon or whatever, when people are saying, well, you don't need to do that, just do demand response. And then you look back at the numbers and say, okay, that really helped. What's the next thing to do?

So, I mean, we've got to move but, again, but obviously the details really, really matter in this area.

MS. BARKOVICH: I just have to say this, Commissioner. I remember that workshop very well and you may recall that the response to President Peevey, when he said that it took longer than mobilizing for World War II that, yeah, and nobody cared at that point what it cost.

CHAIR WEISENMILLER: Right. Okay, that's also true. And that's particularly Martha's headache -- but anyway.

Yeah, I would note, though, I mean it's interesting when you compare across the board, I mean, Agora did sort of the inventory for Germany on demand response. And Germany is pretty heavy industry. So, at least at that stage there's not a major part of the renewable integration of the German picture. And obviously, their industrial customers are pretty well segregated from the cost of the renewable programs.

But, you know, just when they were calling, say, up BMW, saying, well, what would it take for you to drop load? And the answer was, forget it, you know. So, they have to really moved heavily in this direction, at least not the last time I talked to them about it.

COMMISSIONER MCALLISTER: Yeah, I mean related to that, I mean historically in an industrial facility you'd have some behind-the-meter gas-fired, or diesel or something that would take up the load when the grid asked you to drop it. Well, you know, we're not in that reality anymore. So, we have to come up with new behind-the-meter resources that are either clean generation or not generation at all.

CHAIR WEISENMILLER: Yeah, we'll hear from Susan later today, I think.

COMMISSIONER MCALLISTER: Yeah, exactly.

MS. TIERNEY-LLOYD: And just one comment. And I said some of my panelists may shoot me for saying this. But when we were working through the DR proceeding, the

DR application, there was a broad group of stakeholders that collaborated and brought a proposal forward to the Commission.

And that process, Jamie referenced it earlier, it was very labor-intensive, but it was done at the parties' scheduling. It was basically weekly meetings.

But the benefit of that was we got a lot of very disparate parties, with very disparate views to coalesce on a common view and a lot of common proposals.

So, that kind of process I thought was very productive.

CHAIR WEISENMILLER: Okay. I think, with that note, it's probably a good chance to take a break. Again, back at 1:30 and thanks again for your help.

(Off the record at 12:50 p.m.

(On the record at 1:37 p.m.)

MS. RAITT: Is Jean in the room, Jean Lamming? Oh, hi. Okay, go ahead.

So, I think we can go ahead and get started when folks are ready here.

Okay, so we're back and we'll go ahead and get started with Jean Lamming from the CPUC.

MS. LAMMING: So, good afternoon. I'm Jean Lamming. I work in Energy Division and I work on the Demand Response Team.

And I'm going to talk about a staff proposal for integrating energy efficiency and demand response.

Staff put this proposal together in June and we held a workshop on it in June. And our objective was really to spur stakeholder discussion about how to do a limited integration of DR and EE.

So, this staff proposal reflects long-standing CPUC policy to integrate EE, DR, and distributed generation. And that goes back literally decades. And the idea being, at a high level, to maximize savings, avoid duplication and diminish customer confusion. And it really hasn't happened. And there's been various studies that show why, what the various barriers are to this integration.

And one of them is the bullet at the bottom that DR and EE are two different programs. They're done in different silos, done in different applications and proceedings at the Commission, with different budgets and goals. And they almost never coincide.

But this year, for the first time perhaps ever, in January the demand response applications came in from the utilities for 2018 to 2015 at the same time as the energy efficiency business plans came in for 2018 to -- let's see, demand response is 2018 to 2022. EE is 2018 to 2025. They came in, in the same month, so it was like the planets aligned.

And we thought, wow, why don't we try to do something, something on a limited basis? And we really built our staff proposal around the potential study that Mary Ann presented to you this morning.

For one thing, all of the potential projections for 2020 and 2025 are built on the idea, the assumption that there will be market transformation of technology so they'd be automated, end uses will be automated. So, that really needs to happen for us to get that potential.

And she also mentioned co-benefits. And we manifest that idea, also, and that's reflected in the Potential Study in the lowered cost of demand response if you include the benefits that the device, the demand response upgrader device will have for your building in general for saving energy, being more efficient, managing your energy better.

And it also, our proposal kind of just reflects the importance Mary Ann talked about of load shifting and supporting that.

So, the concept behind the Potential Study is really one of piggy-backing on the EE portfolio. As I mentioned, it's limited. It focuses just on HVAC and lighting. And it isn't merging the programs, as some people think. It’s just trying to add demand response into what is really a very big effort. The energy efficiency portfolios spend about a billion dollars a year, and they go into all kinds of sectors to retrofit buildings. They treat new buildings. And we’re just trying to say, hey, when it comes to HVAC and lighting can you add DR-enabling devices and controls when you’re doing all this other work, when you’re outreaching to the customer, going to their building. And we’ll pay for that incremental cost, if you just take us with you.

And we think, you know, this could be very efficient in reaching a lot more people and at least making buildings DR ready.

So, we’re not talking about any new technologies. It’s all existing DR controls and existing EE end uses. It’s just a matter of marrying them through this effort that’s already happening, and making the buildings automated. Yeah, and helping customers be ready for the TOU default in 2019, the residential customers.

And the staff proposal’s built around three prongs. A residential proposal that’s really small, a nonresidential proposal, and then something involving the two Potential Studies, the DR and EE Potential Study.

So, this first integration element is mostly focused on residential. It was developed by one of our consultants, named Karen Herder, who some of you may know. She's an expert in demand response, time of use, and thermostats.

And it's really, the centerpiece of it is really about a prototype of a DR -- of a TOU-friendly thermostat that Karen says doesn't really exist now. And so, it's really trying to capitalize on helping the customer benefit from TOU and not be hurt by the rate increases at certain times of day, that come from TOU, and facilitate their response to the load shaping that Mary Ann was talking about this morning.

And so, the ideas that Karen has is one is to make a very simple prototype for a thermostat that is very friendly to DR, easy to program. It isn't internet connected, so it could be possibly as cheap as $40. And it could be helpful for low-income customers, residential customers if they're in hot climate zones, if they have high peak use they may see a billing increase from the TOU rates that they're defaulted to. And this could actually help them manage that and lower their rates, especially if they have insulation to benefit from pre-cooling.

So, even though it's not internet connected, it could still be considered automated because it would sort of pre-program their response based on the TOU program that is preset in there. And they could just, one time, say, you know, based on a price I would like you to respond. When prices are low during the day pre-cool my house, and then shut off when the rate goes up in the late afternoon, early evening.

And there's a few elements to this. And she also had proposed an internet-connected version that would cost a bit more. And then, it would be available to that whole range of demand response services from the TOU to prices that change throughout the day. Not based on a set TOU, but just more dynamic to actually dispatchable demand response through an aggregator, or the utility that would participate in the supply side markets.

And a few of the elements that she created in this package include a price-to-device idea, which I think Mary Ann touched on, which is where the utility's rate prices at any given time of day, every 24 hours during the day, could be sent to the customers, directly to their device. So, their thermostat could respond accordingly to the price.

And she also has a proposal for making the lexicon around the different time periods, and they have all different kinds of names. You know, super peak, super off peak, rush hour rewards. They're called all different things. And she's proposing to create a common language, so whether you have an EV that you're charging, or a thermostat, or a pool pump, or you get an electric water heat and it has a control there's a common, simple-to-understand language that you could use for any of them.

So, that's mostly focused on residential. And then, we also have a nonresidential proposal that includes six different ideas. And this also, these ideas, also we leveraged our expert consultants, including Lawrence Berkeley National Lab, to help us come up with these ideas.

And I don't know if we really have time go through all of them because I think I'm supposed to be done right now. But, basically, there are six different end uses and controls. Again, they're not new, but we're just trying to marry that DR control into the energy efficiency end use, and control when the energy efficiency program goes out. And they focus on HVAC and lighting. And there are a number of different ideas, mostly for existing buildings, but also for new construction.

And so you can see energy management. And again, the concept that we could pay for that through -- it's actually energy efficiency funds that are sourced from the demand response portfolio could make up that incremental cost. So, the customer's building would be DR ready and they wouldn't have any extra cost to respond to different rates, or to participate in a supply side program.

And some of these have a lot of potential. Like, I'll just mention the variable frequency pumps and the drives, the Potential Study mentions have a lot of potential. The pumps, they were specifically -- I was highlighting the irrigation systems that, mostly in California, aren't internet connected. But if they were, they could respond by taking load, or shedding load, depending on the rate and the grid need.

So, all of this is trying to meet grid needs of the future.

And integration element three, we do an Energy Efficiency Potential Study, I think it's every two years. And Lawrence Berkeley's Demand Response Potential Study was the first one we've ever done. It came out in March.

So, the idea is to integrate them, as much as we can, to address how EE and DR relate to each other. Some people say EE cannibalizes DR. But, you know, what's that relationship? How does that happen when you look at those together?

And also, the co-benefit idea from LBNL. And LBNL, as Mary Ann explained, had some cutting edge, rigorous technology they used in their study. The built-from-customer load shapes into supply curves disaggregated by end use. So, it might be possible to include some of that methodology in the EE studies.

And just it could better feed into our integrated resource planning process that's looking at all resources kind of on an even playing field, and seeing which is most cost effective and best to use.

So, this proposal is being commented right now in a formal process and written comments. And there's been an array of different comments. Some support, some concern, some tweaking. And so, it's kind of up in the air as to what will happen with it, whether it will be incorporated, or some part of it, or it just won't get traction. We will not know that for at least a couple months.

And I think that was mainly it. You can read it. You can find it at this link on our website. And I don't know if anybody has any questions?

COMMISSIONER MCALLISTER: Thanks for that. I really appreciate it. And just FYI, just yesterday, I think, sent a letter over to Commissioner Peterman, in full support of this limited integration. So, I certainly have gone on the pro side of this. I really hope it succeeds. So, thanks a lot for that.

MS. RAITT: Great. So, next we have a presentation from Ahmad Faruqui, from the Brattle Group.

MR. FARUQUI: Thank you very much. It's a pleasure to be here. I will talk about tariff reform. And you might be wondering how does tariff reform fit into demand response?

Well, very, very briefly I'll make a comment on that. Which simply is that in my view tariffs that are cost-based provide the best mechanism for customers to lower their usage, to shift, shed -- what were the other two -- shimmy, and then there was -- yeah, I'm trying my best not to use the other combination of "S" words that may come out.

(Laughter)

MR. FARUQUI: So, basically, in my view, if the tariffs are cost-based, they're reflecting the state of the system, whether it's an annual perspective, or a monthly, or a daily, or an hourly, or minutes or seconds perspective. If we are in a position with smart meters, and smart IT systems, and California is a world leader in all of those, then I see no reason why the price signals couldn't just let the customers make their own decisions.

If they want to consume and comfort is important, let them do it. If they want to save money, and shed load, or shift load, or do any of the others, then it's a choice for them.

We are a market economy. We're not a command and control economy.

So, what I want to say is I'll try to push the envelope a little bit, and it might make some of you uncomfortable, for which I am alerting you in the advance.

The remarks I am presenting are my own and nobody has asked me to say these things. These are not even the views of the Brattle Group. These are my personal views based on 40 years of working in this space.

The 40 years that I mentioned began in the mid- to late-1970s. That was what I'm calling the first wave of pilots. You might remember Jimmy Carter in that era, and the National Energy Policy Act, and all of those good things. And PERPA in particular. There was a big push to do load management, as it was called back then, and time-of-use pricing was regarded as cutting edge in those days. It's no longer cutting edge. But it was in those days, truly and significantly. And people just didn't know whether customers will respond to time-of-use rate. Will they understand what is a peak period, what is an off-peak period? All of that stuff was there and it was settled very comfortably.

And I have very limited time, so I can't go into the details. But I believe all of you have the handout, or at least access to it.

There are lots of studies I've referenced at the end of the deck, which you can read at your leisure. All of the statements I'm making are based on empirical work that has been published either in trade journals or peer review journals.

So, the first wave showed us that customers understand time-of-use pricing, they respond to time-of-use pricing. And, yes, not everybody responds, but some respond a lot, some respond a little, and some don't respond at all. Human diversity is a good thing and that's what you have in every market. Why some people shop at Macy's when even the items are on sale, and some shop whenever they want to. That's just the way it is. We can't force people to do things. They'll just live their normal lives in a market economy. They do that for everything, like airline fares, like shared driving services, all of those.

But for electricity, we have said, well, you know, we have to protect them. We have a very paternalistic attitude towards our customers. These are the same customers who are smart in every other aspect of life. When it comes to electricity, we have to protect them and guard them.

So, that's what the first wave was designed to dispel. But it failed, it didn't dispel the notion, partly because the meters were not there.

And so came the second wave. And the second wave was in the 1980s and 1990s, and there was a second generation of pilots that were done. Some had a dynamic pricing element to them, but there were still pretty much variations on time-of-use rate. Three periods or two periods was the big question. Should the peak period be 12 hours long or 6 hours long, that was the question.

There were no smart thermostats, there was no internet. There were no, nothing, right, in terms of new technology.

That came with the third wave. The third wave was triggered by the California Energy Crisis, which I know is very well known to everyone in this room. 2001-2002 the PUC started the proceedings. And it was on demand response, smart metering, and dynamic pricing. I may have gotten the words wrong, but that's basically what it was.

And then came the first pilot, called the Statewide Pricing Pilot, that California did with the three IOUs. A large working group. That's where some of us met for the first time. And I will not name names, but if you were there, you know who you are.

And in that, we showed conclusively that not only did time-of-use pricing work, but also dynamic pricing worked. It even worked with inclining block rates. You could combine all of those things and if you explained the message simply to the customers, then they will respond.

Again, not everybody will respond. But what was shown was if the price ratio is 5-to-1 for the critical peak price, residential demand will drop by 13 percent. That's a lot if you think of all the residential demand that is out there.

And we got into a debate, with somebody saying to me, well, 13 percent is a small number. I said, you multiply 13 percent into the residential load of California and that is a very large number. Actually, anything above 5 percent would be considered large, 13 percent is pretty significant.

So, the smart meters were deployed. And as far as the pricing issue goes, not much happened. They were voluntarily offered, some customers took it, some didn't take it. Maybe not the best kind of marketing was done, the education was not there.

And I'll show you very soon, as I put California in global perspective, that California is not the global leader in electricity pricing. It has fallen behind. It used to be quite a ways out there. Certainly, the smart meters were deployed really fast, but pricing didn't come as fast.

Then came the fourth wave, which is what we are in now. And you now have demand charges and three-part pricing being considered. As you have prosumers coming in, you have DERs coming in, you have issues across subsidies between people who are not paying their full freight versus those who are. How do you deal with that? So, that's the fourth wave. It's obviously very controversial, it's about net energy metering and all of that good stuff.

The fifth wave is just about to start and I believe a CEC's playing a big part of that, with pilots focusing on transactive energy. Peer-to-peer transactions are sometimes what they are being called.

There's interest in that, and not just in California, but in New York, and in Europe. And, actually, I was talking to their utility in New Zealand the other day, and they're very interested in that, too.

Now, it is admittedly science fiction, it's very futuristic. But again, it just goes to show if we just do time-of-use rates where are we going to look like in the global scheme of things?

So, the first wave, I already mentioned it. This is just for your reference. There is a paper there which summarizes the results of the 14 pilots that were carried out by DOE. And some of the pilots were very poorly designed.

So, what happened in the second wave, EPRI, which I know is represented here, took the results from the top five pilots and found that customers were showing very consistent evidence of consumer behavior, or demand response, as you might call it now.

But the smart meters were not there and, therefore, not much happened. A few utilities decided to move ahead with mandatory energy-based time-of-use rates with their very large customers. This was in the Mid-Atlantic Region.

Eventually as restructuring arrived, those initiatives fell by the wayside.

If you look at the country today, just about every utility has time-of-use rates. Residential, they’re optional. And, typically, they have one percent or fewer of their customers on those rates. They’re not marketed. They are just there so that is in the filing to meet the regulatory requirement. There’s still apprehension, and fear, and reluctance.

The third wave, the energy crisis, we now have more than 40 pilots, featuring more than 200 energy-only pricing treatments that’s without technology. If you add the technology and I’ll talk briefly about that, you’re at 330 treatments being tested around the globe.

In the U.S., we have 50 million households with smart meters, but only a few million on smart rates. And now, very shortly, I will talk about the fears that are keeping us from going there. Mostly, they are about bill volatility. They’re fear that my bill will be volatile, or my bill will be higher, and to save money I’ll have to disconnect my appliances, I’ll have health issues. All of those fears have been addressed in those pilots, but the messaging has been poor. So, that’s what I think needs to be done is to have better messaging.

Just a couple of snapshots. So, the graphs I’m showing, the X axis is the peak-to-off peak price ration would be a time-of-use rate or a dynamic pricing rate. So, if your average rate was 13 cents, and your critical peak rate was 65 cents, it will be kind of like the 5-to-1 ratio.

So, what I'm showing is time-of-use impacts on the left side, dynamic pricing impacts on the right side, and we have fit these regression curves on the day, from a variety of pilots, just to illustrate the collective meta-analysis, if you will.

And what you find is that if you tilt up the ratio, peak to off peak, you get more response. But at some point it begins to come at a diminishing rate. So, the first derivative is positive, second is negative, for those who like the calculus.

And then, you get into enabling technologies, and that's what I'm showing here. Like a smart thermostat would be a good example of an enabling technology, but there are many others as well.

So, I'm showing now, in each graph, data with technology and without technology, the different colors. The lighter color is with technology, the darker color is price only.

And the only thing I want to emphasize is the two arcs that are being shown there, the arc at the top in each graph is the arc with technology added to price. And the other one is just price by itself. So, you can see that significantly higher response.

And so, to some extent, the conversation that occurs at a lot of DR forums is, well, we can have price programs and we can have technology programs. I personally don't like that because I think they are one in the same.

We should have cost reflective prices, encouraging technology. We should have technology enabling bigger price response. And ultimately, if there's bigger price response, the technology effect will feed back into the prices and it will settle this debate of whether or not the customer can response because they're be enabled with the technology.

Of course, EPRI, where I worked for 11 years along the way, had this mantra of getting the prices to devices. I think we are all now almost there, it seems, with the technology. And transactive energy, I think, is a good example of that.

Okay, the fourth wave demand charges would come in. But by the way, demand charges are not new to this industry. They have been around forever for C&I customers. Why? Because a lot of the costs of the grid are driven not by the amount of power being delivered, but the size of the grid, the size of the connection. And that has been accepted for C&I customers forever, not just in the U.S., but throughout the globe.

For residential, the meters were not there and, therefore, it was not implemented.

Well, now we have a situation where you have negative prices, you have negative load, net load, so the cost for the grid still has to be recovered, and that's where the demand charges are coming in.

We don't know much about how customers would respond to demand charges, residential in particular. That has been one of the challenges.

We have only three pilots, unlike the 45 pilots for energy-based time-of-use and dynamic pricing rates, there are only three for demand charges. So, there is an opportunity here to do more pilots.

And then there is the fifth wave. The fifth wave is where the customer buys a baseline load shape, which could be their historical kW demand, or monthly kilowatt hours, or just a projection. They'll lock it in. And so, with that load shape, their bill is fixed. There is no fear or panic that I could be, you know, paying an extra hundred dollars just because I had a big party one day, or something.

As far as deviations where the baseline are concerned, those will be purchased on the wholesale market. So, this is an idea, very similar to how wholesale markets function today. People buy forward contracts and the deltas are bought in the real market, the real-time market. This is applying that same idea to residential customers.

And, obviously, sophisticated technology is needed and that's where these pilots come in.

Okay, so let me just comment briefly on what's happening elsewhere. And my theme is people are going beyond time of use. So, in Ontario, Canada, which by the way started to deploy smart meters at the same time that California did, but they moved ahead and they implemented default time-of-use rates, like a round the year 2008-2009 to their 4 million customers.

They didn't do any pilots to see whether that would work or not, they just did it. The premier that we're going to do it because that's the smart way to move forward with smart energy and smart prices. They just did it.

They have analyzed the data, and we were one of the parties analyzing, just you know. We found that customers in the aggregate, all residential customers reduced their peak demand by 3 percent. Now, you might say that's a small number, but it's a big number when you look at the entire residential peak load.

Now, the problem is time-of-use rates, in today's environment, lock the pricing periods. And we know there is no such thing anymore with renewable technology, with DERs of different kinds, with duck curves and what have you, unpredictability of load. Not only just because of the weather, but because the technologies has become a reality.

So, locking in the pricing periods and the prices is not going to be very fruitful in this new era. And so, the Ontario Energy Board wants to do pilots with dynamic pricing just to see where can they go beyond the time of use?

By the way, Texas is looking at something similar, as well. Texas is a very different market. But what they're doing is they have a competitive market for retail, for energy. But for distribution, they going to just move to totally a fixed charge. So that it becomes not an issue whether the customer has solar or not, they still have to pay the cost of being connected to the grid 24/7.

A decision has not been reached in Texas. They're looking into it, just to be clear.

Okay, so then we go to Oklahoma. Now, that's the middle of the country and usually people don't expect innovations will take place there, right, that's the stereotype. Well, they have really done what nobody else has done before on either coast, or in any country, expect for Spain, and I'll comment briefly on Spain.

So, OGNE rolled out a dynamic pricing rate, tested it, and then rolled it out. They have 130,000 customers on that rate today. It's a five-period dynamic rate. Depending on which day type it is, the price is higher, and higher, and higher or, depending on your point of view, lower, and lower, and lower.

Okay, they also provide smart thermostats to those customers.

Here's the difference. The utility does not control the smart thermostat. The customer does. The customer programs their preferences into the settings of the thermostat to reflect their priorities. So, if the price begins to rise, their temperature setting will change with the price. They set it and then it does it automatically. It's not controlled by the utility.

And they are very proud of that. They say, we let customers make their own choices. And some customer could say I don't want my thermostat setting to change. That's fine, that's up to them.

Average peak load has dropped by 40 percent. That's 4-0.

And in their case, shed is important, I guess using the terminology.

An average bill savings amounts to 20 percent of the customer's bill. It's a voluntary program, they're not forced onto it. And believe me, that's the only place I've gone where the cab driver, and the person sitting next to me on the plane knew about the program.

They have done really a great job in marketing it, okay.

Let's go briefly to Maryland. Peak time rebates are very popular there. The Commission didn't want to do time-of-use. The Commission didn't want to do to critical peak pricing, but they agreed to do peak time rebates.

So, the utilities bid in the customer's reductions into PGM. That's how they monetize the rebates. And they had some pretty significant savings numbers, as you can see on this particular slide. They have two utilities doing it, BG&E and Pepco Holdings.

Australia. They are beginning to look at peak time rebates. That's my last bullet there. And just look at the magnitudes of the rebate that they have come up with, $5.00 per kilowatt hour. Now, these are Australian dollars, admittedly, right. So, you can multiply by 0.75. It's still a very big number.

Maryland is paying $1.25. Why? Because these folks have significant capacity constraints and they don't want to add to the capacity. They're saying to their customers, if you cut your load during these critical times, we won't have to expand the grid. It's a purely market-based approach.

Okay, the UK is piloting a peak time rebate program targeted specifically at low-income customers. They have done a couple of time-varying rates. They have a lot of wind energy coming on, so the tariff they have is called the "wind twinning" tariff, or maybe the "twinning" tariff. I don't now how it would be pronounced in Britain.

Ofgem, which is the regulator there, the national regulator, is looking at new ways to increase the role of price-responsive demand, including the possible introduction of firms, like Amazon and Google, into the marketplace that they can offer dynamic pricing products, okay, to American firms. The Americans are coming.

Now, they have had time-of-use rates, by the way, for a very long time. They have this rate called Economy 7 that goes back at least six decades. They have 13 percent of their customers on that time-of-use rate.

So, they have time of use, they are beginning to look at non-time of use.

A quick move over to Hong Kong. The China Light and Power, they did a pilot for 2,000 customers and peak time rebates. It was very successful. You know, expanding it to 27,000 customers who have smart meters. The others don't. As that expands, they're going to offer it.

And by the way this rate, which is a peak time rebate, is widely criticized in the U.S. It certainly has been in California. But it really has been very popular everywhere else.

And, of course, the challenge is how do you measure the baseline, and we all know those issues. But if you can agree on how the baseline is measured, the big advantage here is there are no losers. At least not on the surface.

Now, you can argue statistically there are free riders, there are losers. But by and large, even in New Zealand, the utility I'm working with, they're going to do this and nothing else because it gets over that hump of I will have a lot of people losing money.

I know I'm running out of time. What I want to do is briefly talk about the barriers to tariff reform. Fear of the unknown is the biggest barrier, even 40 years after a lot of the unknown has become known, we continue to have that nightmare that this will cause a social revolution.

The fear is the bills will rise for some customers and they will complain. Even though bills fall for the majority of customers, a small, vocal minority will create a fuss, the media will pick it up and it will become a challenge.

The third barrier is the new rates would not be understood by customers and so confusion and distrust of the utilities. No CEO would like to have customer satisfaction plummet as they roll out these rates. I talk to many of them and their biggest fear is what will be the backlash if it happens.

Okay, so there's a lot of fear which I think is not justified based on the 300 plus pilots that are being done, but it's still very strongly held.

Then there is a concern about low-income customers and small users, that they'll be harmed by the new rates.

There are a total of ten barriers. The others are listed here. Customers with disabilities will be harmed. Customers will not respond. The rates will fail to promote economic efficiency or equity. The rates will require new meters in building systems. The rates will impose an extra load on customer service staff. And revenue volatility will rise. That's actually mentioned by CFOs of some utilities.

So, it's a combination. It's like a witches' brew between the utilities, the regulators, the customers, the stakeholders. So, people are inclined to just say leave it alone, don't touch it.

Okay, so how do we move forward? I'm going to assume that all of us agree that cost-based pricing is the key to the successful development of the electricity system. And so, we have to move forward. We have smart meters, now. We have 300 plus experiments being done to show that it works. So, how do we overcome the barriers?

Well, first of all, the first thing to do is understand how customer bills will change if the new rates are implemented immediately and customers don't respond. So, take your sample of customers or your population of customers and see what will be the bill impacts on the small users, in particular and those who are peak users, as well.

And then, identify those groups and find ways to mitigate the bill impacts.

Simulate the impacts of the rates to study the likely customer response. Those are the prices higher in the peak, or lower in the off peak, there will be some price response. We have 300 pilots telling us that. So do a simulation and you will that the bill impacts, which were negative, a lot of them will become positive in the sense of being good.

Third, engage in a customer outreach program to explain why the tariffs are being changed. This is often not done. People rush into it. Make sure the new rates are clear and in understandable language.

Enlist neutral parties to endorse the change. The people who are insiders don't know how to talk to the industry at large. Also, they are usually vilified as being, you know, biased or what have you. I mean, every time I've testified before the PUC, on behalf of some of the utility, I make it very clear to my neighbors that I am not doing what I'm doing.

But one time I made a mistake and I said to somebody, I'm going to testify before the PUC, and the comment was "that's a crooked agency." I didn't even mention I was testifying on behalf of the utility.

So, we have a huge challenge in California. And by the way, this is not a California-special, they're in every state. It's the fish bowl environment we live in when we are regulated and people have impossible expectations.

So, engage in a customer outreach program to explain why tariffs are being changed. Get the third-parties, use social media to spread the word.

Look at Oklahoma Gas & Electric, how did they do it? Nobody calls them crooked. I've been there. People have the most incredible -- because they're saving money. That's what -- and they will explain in a simple way how to save money. And social media was used. So, we can use new techniques, just like every other industry does.

Also, let's change the rates gradually, over a three- to five-year period, or provide bill protection. And that will protect everyone, initially. Okay, that's one approach.

Or, for the first few years make the rates optional, particularly for low-income customers, small users, and disabled customers, or provide them financial assistance for a limited amount of time.

None of these, by the way, are rocket science. I mean, these are pretty obvious things, but these are obvious things that are never done. Most of the time they're not done and that's why we have all those stories.

And then, you know, my favorite idea is a subscription concept where the customer just buys or locks in their historical usage and the historical price, so there's no way they'll be harmed. They are being protected. And then, they buy or sell deviations.

By the way, this is now called transactive energy, and it is. But for many years Georgia Power has done this very successfully for their large C&I customers. It's called real-time pricing. The customer buys their load shape or baseline. It's not free, they have to buy it, so there is no issue of gaming or anything. They just buy it.

And then, the deltas are based on whatever technology they have, okay.

And then, lastly, conduct pilots to test customer acceptance and load response to the new rates. And let's not just keep testing the simple time-of-use rates over and over again.

Okay, so to conclude, tariff reform has gone through five waves. This is the fifth wave. Some of us will retire in the fifth wave and the rest of you will get to see what happens in the sixth wave.

So, while many pilots have shown that customers respond to time-varying rates, there's still a reluctance. We have to address the reluctance. It is very real.

And there are several ways in which the transition can be made, as I mentioned. And if we are doing pilots, let's focus on the fourth and fifth waves, and not redo the first, second, and third waves in those pilots. Thank you.

CPUC COMMISSIONER GUZMAN ACEVES: Thank you. We were talking earlier this morning about some of our initial pilot results in PG&E territory of the opt-in.

MR. FARUQUI: Right.

CPUC COMMISSIONER GUZMAN ACEVES: And some of them are concerning. So, I know some of this is not just misperception, but actuals. And I'm intrigued by the dynamic pricing of rewarding, you know, instead of what we're seeing in some of our results, which is punishing, particularly the low-income and middle to low-income customers.

So, I will definitely look at your research papers here and these other country examples where they're using positive pricing.

MR. FARUQUI: Thank you. And one comment I will make is that in some areas what they have said is they will offer the rebate program just to the low-income customers. And then everybody else will be on like a standard dynamic rate or a time-of-use rate.

I believe the UK is doing an analysis of PTR, peak time rebates, just for the low-income customers, for the very reason you mentioned.

In Australia, they were planning to exclude them. Not just low-income, but also people with medical issues, or anyone who wanted to be excluded could present a case for that and then they will be excluded for a limited amount of time.

COMMISSIONER MCALLISTER: So, thanks for that. I really appreciated, you know, the focus has mainly been on residential here so, you know, I think we should be clear that nonres is a pretty different beast.

But I guess I'm wondering what is your feeling on customer fatigue; have you looked at that and sort of have a sense of how much that actually dilutes the kind of value for the grid? In terms of, you know, what we often hear from utilities who have these programs is that, oh, gosh, you know, the fifth day of a heat wave my load shape reverts back.

So, I guess, maybe you can just comment on that behavioral issue?

MR. FARUQUI: Sure. So, that was tested in some of the pilots. They called CPP events on consecutive days. Sometimes twice and sometimes thrice. There was no degradation of response, at least in the tests I have seen.

Some people have also used fatigue in the sense of fatigue over time. So, the first year there's excitement, the second year it sort of comes down, the third year it goes down even more.

Well, the Baltimore Gas & Electric pilot was done for four years in a row, precisely for that, and they found no evidence of fatigue.

So, for the most part, I think the empirical evidence is that people continue to respond. But I can tell you, as a participant in one of the direct load control programs, myself, in California, after the third day it was called my wife said to me, you get us off the program.

I said you can call. She said, no, you will call.

(Laughter)

COMMISSIONER MCALLISTER: That's demand management, I guess, right.

MR. FARUQUI: Exactly. Exactly.

COMMISSIONER MCALLISTER: Thank you very much, appreciate it.

MR. FARUQUI: Thank you.

MS. RAITT: Thanks. So, next we'll move on to our panel. So, if the remaining panelists could come up to the tables?

So, our panel discussion is on Business of Demand Response in the Policy Marketplace. And we have Gabe Taylor as our moderator.

MR. TAYLOR: Good afternoon. Thank you very much for sticking through a long and very information-packed day.

I'm going to take a little bit of a break from tradition with this panel. I'm going to let them introduce themselves. We've asked each of the panelists to prepare a very brief presentation.

We've heard a lot about policy, and about theory from academics, and now we get to take a little bit of a different direction. We're going to hear from some industry.

We have five companies here represented. These are a cross-section of the business models, currently in the industry, that are successful, that are earning money of off demand side and energy management.

And I'm going to pass the baton over to, first, ENGIE, and then we're going to just go in the order on the agenda.

MR. PANZER: Thank you for having me here today. Admittedly, I haven't spent as much time in the regulatory or policy environment since I left PG&E, and that's a common thing with ENGIE. And as you hear my points today, you know, keep that in mind. We more respond to what happens in the regulatory environment, as opposed to being a heavy active participant.

So, Ecova, the first slide here really just shows who we are as part of a larger organization. We generally like to consider ourselves the largest organization nobody's ever heard of. About 150,000 people worldwide, about $70 billion in annual revenues.

And ENGIE is headquartered in Paris, France, was heavily involved in the Paris Climate Conference. And with that, made the dedication that they were going to shut down their coal plants around the world and really focus in on decarbonization, decentralization, and digitization. And that's been our motto for the last few years, and will be going forward.

It's a very painful process transitioning in that direction, but it's the right direction, in our consideration.

Ecova is part of one of the five business units in ENGIE North America, called ENGIE North America Services. And with that, I'll dive into who Ecova is, in a moment. But this slide shows the other players as part of our business unit, OpTerra, EVbox, ENGIE Services, and Green Charge Networks. And, really, we're working across a lot of different areas, EV charging infrastructure, demand response, energy efficiency, storage, DG, working across the value chain from designing and delivering programs, doing data building, analytics, all the way through project development, project implementation and facility management.

As far as Ecova goes, you know, where we really sit in this big mix is, you know, we've really kind of repositioned ourselves and are really focused on a world of energy as a service.

We have two different business units. One is focused on actually working directly with facility customers, as we call them, or the national account customers. We work with about 700 national account customers that targets the Best Buys, Verizons of the world, doing traditionally data management, expense management for these customers, working at about 700,000 buildings across the U.S.

And on the other side of our business, we're traditionally an energy efficiency program implementer.

Looking forward, though, what we're really looking to be in and what we're really looking to do is offer energy as a service. Really, you know, go in and do the work to upgrade the facilities and take over management of their buildings. And I'll dive into that a little bit more as I talk about one specific thing that we're offering for utilities.

Ecova's Utility Solutions, we've been around for a while. We're working with more than 50 utilities across the country. We acquired Retroficiency a few years ago, which is a data analytics and software, as a service player that really can dive deep into buildings, understanding what's actually happening within them, really using advanced building analytics that embeds energy -- sorry, I'm drawing a blank on what's embedded in there.

But anyway, so really using the data analytics, though, to be able to take data from utilities and really be able to prioritize the market. Look at like who are the customers in the market that we should be targeting for different initiatives and how should we be engaging them? So, if we can go off and understanding what's actually happening within the building, before we engage with the customer, we can have an advanced conversation with the customer to begin with.

And that really plays a part in the solution that I'll touch on really quickly here. So, this slide here shows the different programs that we offer to utilities. Traditionally, we've been more focused on the residential side, but really we're focused more heavily on building out on the commercial side.

Well, the laser's getting lost in there. But SMB Managed Energy is a core part of that focus moving forward. Essentially, you know, I mentioned energy as a service a few times. And what we're offering for the

SMB customers through the utility channel is an energy efficiency and demand response offering.

As I mentioned, we respond more to regulatory and legislative activity, as opposed to being an active participant. SMB Managed Energy was really developed around, you know, some of the key legislations that have passed over the last few years, including AB 802, AB 793, and SB 350. We've really developed a solution that works within the world of meter-based savings, really focuses on bringing controls to the small to medium business customers, and really tries to motivate the market.

How we do that is essentially we say to customers who lack time, who lack interest, who lack expertise in their energy usage that here's an energy efficiency and demand response project. We are going to pay for this project for you. The project is going to be building controls. We're going to put BMSs in every building. It's important to make the building smarter and really put controls in there.

We're going to optimize the HVAC and we're going to do lighting retrofits, where lighting retrofits haven't already happened within the building.

Again, we're going to pay for the entire thing for them, using an off-balance sheet transaction, which is going to allow them to not impact their ability to borrow money. And then, we're going to lock in their monthly payment, they're monthly utility bill, and we're going to take over the performance risk, which means we're also going to take over the management of the assets for them.

So, that basically says to the customer, go focus on being a pizza restaurant, or go focus on brewing coffee, or being an accountant, or being a dentist.

There have been a lot of great programs and lot of great design put into programs to target the SMB market over the years. But we're still looking at, you know, only about one to two percent participation by SMB customers in utility programs.

And because it's such a hard-to-reach market, we've finally moved in the direction of saying let's enable them to figure out how we can actually just sign them up and we'll take over everything from there.

And in that, as we're going off and going and putting a BMS system in every single building, it's important to make sure that everything is auto-DR and enabled. We're not serving as an aggregator, but we're serving as a program implementer.

And I'm sure -- I hope this leads to more discussion and more questions as we go, but I'll pass it on, now.

MS. KENNEDY: Thank you. I'm going to use the one up here because I got it at the last minute to show you the live demo of one of the hybrid-electric buildings we just built. You know me, I can't follow a script.

My name is Susan Kennedy and I -- I'm short. My name is Susan Kennedy. I'm the CEO and founder of a company called Advanced Microgrid Solutions.

(Pause)

MS. KENNEDY: Okay. So, I'm going to show this to you quickly and then I'll describe what we're doing. So, we're actually -- we're focused on putting load control technologies in buildings, including advanced energy storage, automated software controls, and data analytics in order to control the load of the building to create high efficiency, load control on the consumer end, and then also provide grid services on the utility side.

So, this first building we're going to is a 15-story office building in Orange County. It's about 250,000 square feet. It has a 250 kW, 6-hour battery system.

And let me see, today's not a very interesting day. So, we'll go to -- so, this is yesterday, where you can see this is the actual load of the building, and this is the load, this is the battery going on and off to control the load of the building, and this is what the grid sees.

I'm going to show you a more interesting day. Well, so you can see here's a couple of interesting days when the weather, you know, created a little bit more need to do some load reduction. And you can see that these are very large buildings, very large battery systems. This is the month of July.

So, if you can see the grayed-out area, this is what the peak load of the building would have been. This is 30 days of load curve superimposed over each other for the entire billing period of July. This is what the building load would have been, the peak load would have been, and this is what the building load is after the batteries are in operation.

So, this is permanent load reduction. The batteries are sized in a way to harness the entire building load. The reason for that is because you want to plan for the global peak. Not just for the one- or two-day heat wave, but you want to be able to provide permanent load shifting on the third, fourth, and fifth day of a heat wave, so that the building owner does not have to change their operations, or suffer any economic losses for participating in demand response.

And so, by sizing the battery system in such a way that it can provide two functions simultaneously. One is the permanent load shifting and peak demand reduction, but also utility dispatch.

Let me go back to one day and you can see what it looks like. Hold on a second, let me go back to one day where you can see how this applies.

So, this was July 6th. Oh, this is a really bad day. Why did I pick that day? Never mind. There was a better day that actually showed the -- I'm going to go -- can I go to my slide show, now, so I can show you the pictures? I thought I had that day down. I've got a better picture of it.

Okay. So, Southern California is ground zero, right? You actually -- all the stuff that we've been talking about today, which I absolutely agree with, and I think I've agreed with pretty much everything that has been said.

The one thing I would really inject here is that a lot of the planning that goes on takes months, years, sometimes many years in order to implement changes. You have a proving ground in Southern California, today, around demand side management.

When San Onofre was taken offline, Southern California became ground zero for a changing grid around the world. SONGS was a 2,500 megawatt, zero emission resource in a capacity-constrained basin. Southern California Edison suddenly was thrust onto the front line of figuring out how to replace this resource with demand side management, because you can't put a peaker plant in downtown L.A. You cannot solve the problem -- even if you could put a peaker plant in various places in downtown L.A. the circuits are at or near capacity, so you wouldn't be able to move the electrons around in a way that actually provides the kind of reliability in a cost-effective manner.

And so, solving this problem, the ratepayers are going to pay for this problem. They're going to either pay for the distribution upgrades in order to provide the resources, or they're going to be paying in rates to pay for generation resources in order to solve the problem, or they're going to be paying in rates in terms of the demand charges, and the time-of-use rates to try and facilitate them shifting their load off peak.

And so, SCE began a groundbreaking experiment in supply side demand response, when they replaced San Onofre. They bought almost 500 megawatts of battery storage-enabled technologies for the L.A. Basin. And much of which had never been done before.

And the projects, if they succeed or fail in Southern California, they're coming online starting the end of this year and into next year, it will impact the demand response for the next generation. There's easily more than a billion dollars in private sector capital investment in demand side management programs in the Los Angeles Basin to replace San Onofre.

If we succeed, it's a beacon for demand response around the globe. If we fail, it is a warning signal to investors not to invest in a business model that are not yet mature enough, at the utility level, in order to be able to survive the regulatory.

The key issue is what is the value proposition to the end-use customer? Load-modifying resources, it's all about the economics. Value to the grid, value to ratepayers, value to end-use customers. And it starts with what is the value to the grid?

A load-modifying resource is of limited value. The first day you might get 98 percent response. The second day of a heat wave you might get 78 percent. On the third day, you're lucky if you get 50 percent. That means the utility has to buy the peaker plant in order to have it on -- because they have to buy resources for the third day of a heat wave, not the first day.

So, in terms of the value proposition to the end-use customer, it starts with if it’s not that valuable to the grid, it’s not that valuable to the end-use customer. And a lot of the end-use customers are dealing with the reliability issues, like putting diesel and gas-fired generation in order to be able to shift load for demand response.

So, the advent of battery technology, with automated software control systems creates a level of value to the end-use customer, which is now groundbreaking. It is the killer app for demand response.

And so, what do you do with a -- when you have a battery-backed demand response, it becomes truly supply side demand response, where it enables you to shift and reduce load without impacting the operations, and do so in seconds, in sub-seconds in some cases.

Peak demand reduction, load shifting, and load shaping around solar, electric vehicle charging, power quality and reliability, and controlling EV charging infrastructure cost.

Large C&I customers are installing these technologies today because they want reliability and cost control. The key is how do you enable, how do you take those technologies and design them in such a way that you're also providing grid resources? Because that's how you create the value proposition that is enough of an economic incentive for the end-use customer to spend a lot of money, on very expensive technology, to harness the whole load is only if you can actually make that load available to the utility as a distribution level resource and become part of the solution.

And you say from the live shot that I just showed you what a hybrid-electric building actually looks like in operation. When you put a battery with advanced information systems, that's the sensor data and the meter level data that you're getting from installing the system, with advanced diagnostic and optimization software, and OpenADR controls, you have a fully integrated system, energy management system that can deliver not only load shifting and peak demand management, but microgrid controls, emergency generation, monitor-based commissioning, power quality. All of that data is available in real time. Market products that are not just resource adequacy capacity, but you can use the smart inverters to provide reactive power to the grid, frequency regulation, load following. That building load becomes the most flexible resource and the most cost-effective resource. The battery is the most expensive piece of technology. The rest of it is the telemetry and the software controls.

So, scale matters in terms of being able to make this a cost-effective resource. And what you're looking at here is the gray is the building load, without the batteries. The dark blue is the battery activity. So, it's charging at night and then during the day it's discharging and carrying the load of the building. So, you can see the building flat lines at the top, permanent load reduction.

The deep pocket of gray is a simulated dispatch, from 2:00 to 6:00, where we get a signal from the utility and we switch the building to battery, just like you would a hybrid-electric car. It literally shifts instantaneous to battery, like a hybrid-electric car.

The data we're using, we're providing to the building owners that includes energy use intensity, carbon intensity, renewable content, and cost.

And so, even our most sophisticated energy users are using the data from our systems to not only do their procurement planning, but also their energy efficiency benchmarking, trending, monitor-based commissioning. And then, their sustainability officers are using it to generate reports on renewable content and energy cost.

By putting these in portfolios that are -- so, it's one building is fully optimized, you put it in a portfolio with a dozen buildings, or two dozen buildings, or a hundred buildings and it becomes -- our software platform also optimizes on the portfolio level.

So, this is what the resource looks like to the utility when you optimize and you aggregate the optimized buildings.

Actually, this one's a better one for us. So, this is actually one of our projects in Southern California. These office buildings over here are, you know, all tied together, and they have large battery systems installed. This is what the batteries look like at each of the buildings, and then that's the data that's being spit out from that.

So, this is -- here is that very same commercial office complex we were just looking at. And this is the aggregated load --

Sorry, I'm not on the record. This is the aggregated load of that building. So, when we get a dispatch call from the utility, the optimization software looks at all of the buildings and says where's the building load, how much battery capacity do I have? If the building is using the battery because it needs it, because there's a heat wave and the secondary chillers are going off, it looks to the other buildings in the portfolio in order to be able to deliver a hundred percent of the capacity that was asked for by the utility, in real time.

And so, that resource is highly valuable and it's pinpoint accuracy on the grid. You take 100 megawatts of traditional demand response and you spread it across the Los Angeles Basin, it's nearly invisible to the grid operator. You take 10 megawatts of our projects and you concentrate them around certain substations, that is very visible to the grid operator and very valuable in terms of its use in the wholesale market.

So, I'm going to end there. But this kind of a little bit of a geek-out slide. Because I am actually really excited about combining the data analytics with the load control technology in what I believe is the first generation of system level efficiency, with building-to-grid automated dispatch built into it. That this is the grid of tomorrow. And these projects are actually being built in Southern California today and I think they're going to be the kind of projects that California is going to develop a great leadership around.

MR. EGGERS: It's great to be here. Hopefully, this will be a helpful day for you guys? Or, are we going to switch? Back to you. Does that count in my two minutes that I'm supposed to spend?

(Laughter)

MR. ANDERSON: I'll yield a couple of second when my time's up and make you whole.

MR. EGGERS: Thank you.

MR. ANDERSON: Commissioners, and Mr. Casey, thank you very much for convening this workshop and for inviting me to speak. My name is John Anderson. I'm Director of Energy Markets at OhmConnect.

For those you not aware of us, we are a free service that notifies households of DR events, predominantly residential customers. And we pay them for reducing their energy use during these events.

While we are free and don't require customers to purchase any particular hardware to use our service, you could pick up your computer or your mobile phone right now, and sign up, and be participating in DR within a matter of hours or day, we do also work with many IOT devices. So, smart thermostats, smart EV chargers, smart plugs, and thereby allow customers to auto connect on autopilot, and put it to work for them when they're not even at home.

We are the largest provider of third-party DR services in California, to residential customers. We have tens of thousands of users, signed up with OhmConnect, across the three IOUs in California. We have dozens of proxy demand resources in the CAISO, and dozens of megawatts under contract with each of the utilities, under the demand response auction mechanism.

This business came about, really, as we thought about a confluence of two different trends going on, both in California and other parts of the country. As other speakers today have already discussed, there were some changes underway in the energy markets.

Bruce, from the CPUC, spoke about Rule 24, and smart meters, and access by third-parties to smart meter data. And Jill, from the ISO, spoke about development of the new models, like the proxy demand resource model at the ISO.

So, on the one hand we had these trends in the energy markets. But as you're all likely aware, in recent years we've also seen more and more home automation, more and more internet of things, smart devices. A lot of interest among consumers and households in these technologies, but a recognition at the same time that they're not cheap.

A thermostat that costs $250, a smart EV charger that costs maybe $600 or $800.

So, how could we help lower the cost, lower the barrier of this cost for customers? And one such way is to put these devices to work for them in the energy markets and thereby help finance the cost of acquiring home automation technology.

And so, I'd like to share with you what we call the core loop at OhmConnect. It's really a three-part system of signal, response and reward. Whereby a grid event occurs, we have imbalance on the energy system. We have a price spike.

OhmConnect's proxy demand resources are dispatched by the ISO and we turn that into a distributed dispatch that we send to our user base. And we do that in two different ways.

In the simplest case it's behavioral. Your phone buzzes, you get an e-mail that instructs you when to reduce your energy usage.

However, if you also have automated technology connected, your devices will automatically turn themselves off when the event starts. And, just as importantly, turn themselves back on when the event concludes.

When the event is over, you get feedback on your OhmConnect dashboard, based on your smart meter data that shows you how much you've reduced and how much you've earned for that reduction.

And that's precisely what we show customers in this dashboard that is the first thing you see when you sign into OhmConnect's website, or open our mobile app. You see your performance relative to your baseline in recent events. You see the number of total points you've accumulated and your ability to either cash out those points, or donate them to a charity, or use them in OhmConnect's online store to buy yourself a thermostat, a smart plug, or other smart technologies.

You have the ability to refer friends to sign up for OhmConnect and earn bonus points in that matter. And also earn bonuses for accumulating a streak, for instance, of many consecutive successful performance events.

And through these additional pathways, we've really found ways to keep our user base engaged, to avoid some of that attrition that we've heard about in other DR program. To make this something that is fun to do, exciting to do, something you can compete against your friends and family, while helping California with its energy issues.

And on that note, we see a lot of customers that participate not purely for monetary reasons. We estimate that households can make, perhaps, on the order of $150, depending on how large they are, depending on where they're situated, each year by participating in OhmConnect.

For some households that's a lot of money, for others it isn't. So, how do we get these other households to really care.

And what we've found, quite contrary to perhaps conventional wisdom is that we're not inconveniencing people when we have our events, our Ohm Hours, as we call them. We came into this with a hypothesis that asking someone to reduce their energy usage, turn off their thermostat, turn off their television is an inconvenience, is an imposition and, therefore, we have to compensate them to overcome that.

We're actually finding that a lot of our users enjoy these events. In addition to the money it's a chance to just disconnect, spend some time with your family, take the dog for a walk, go to the park, eat dinner by candlelight. It sounds silly but, you know, the results are in the numbers. And with the user base we have now and the feedback we're getting, we're really excited about the multitude of ways we're able to connect with households, and many of which are entirely new to demand response. Thank you.

COMMISSIONER MCALLISTER: So, it's really quiet up here, but I can tell you that there's a lot of energy, too, positive energy. So, it’s not that we’re not interested in what you’re saying.

(Laughter)

MR. ANDERSON: Good, good.

COMMISSIONER MCALLISTER: But we’re holding our fire until the end of it.

MR. EGGERS: Great to be here. Thanks for having me. Hopefully, this is a helpful day for you guys as you work on these problems.

I’m Matt Eggers. I’m part of Yardi Energy, which is part of Yardi Systems. Yardi is a 30-year-old software company. We serve the real estate industry. We make ERP systems, which is a fancy word for accounting, think Oracle and SAP, CRM systems, which is a fancy word for sales software, and marketing software, and all sorts of other stuff for the real estate industry.

And we also have energy, building control products that we provide to that same industry.

So, we’ve got about 5,000 employees in the commercial side of the business. We have about 12 billion square feet of real estate that use our software on the multi-family side, it’s about 12 million residential units are managed using our software.

And in energy, what I’ll talk about today is what we call the Yardi LOBOS Suite. LOBOS stands for Load-Based Optimization System. It's a software suite that gets installed on top of a building management system in buildings, or can operate as a simple BMS, if none exits.

And it provides a considerable level of intelligence to that BMS. It makes it web-based. It makes it easy to use. It's a GUI (phonetic) for a complicated system.

Today, we generally implement that because people are interested in energy efficiency, and fault detection, and diagnostics. So, we built artificial intelligence systems, algorithms into this that can run a building much more efficiently than it would otherwise run.

Savings by shavings is, you know, one of the industry terms that we apply here. But by just making minor tweaks and responding every 60 seconds to the individual loads that are happening in an individual buildings, you know, say 100,000 square foot an up, we can save a lot of money by changing what the chiller is doing, what each air handler is doing, what each pump and cooling tower might be doing.

We used to sell a lot of this for demand response. We don't, really, much anymore. The office market, at least as we can tell in California, is struggling with its ability to participate, for complications that we'll get into in a little bit. But we still so a fair bit of demand response with existing clients.

And the way the system enables that demand response is here. So, you'll probably be able to see this a little bit better on your handouts, but I'll make some points here.

This is a portfolio of buildings. It's actually -- well, I guess you can't see the pointer on there. It's an Irvine Company portfolio. Some of the same buildings that we saw earlier. And the software is capable of taking a whole portfolio of buildings here, responding to various demand response signals.

Buildings have been preprogrammed for low, high or medium curtailment strategies. They also can be set with multiple schedules so they could respond at certain times, in certain ways and not other times.

And the software goes out to that portfolio of buildings, that actually extends well beyond what's on the screen there and finds the load at the right moment.

And you can see then, at the bottom it adds up all of the capacity. An operator could decide to change a given building or setting from low to medium, or go to a different schedule and deliver slightly more load or slightly less, depending on what the signal is from the grid and what it's worth to the building owner.

You know, these are capitalists and they're going to do these things when it pays off for them to do it.

And the trick for us, in our software, is to have made it really easy and the software hunts and finds the load, and delivers the capability. And there is a significant amount of capability, both in this portfolio and other ones.

We, and some of our clients, like to say that the most cost effective battery chemistry we've ever seen are these buildings. There's a lot of load that's sitting there that can be delivered in different ways, and we can deliver the load by cycling between various floors, between various buildings, between floors in buildings, between pieces of equipment in buildings in order to have little to no impact on tenants and the business of those operating in the building.

So, there's a lot of capacity here. It's just for us to do this more with these clients and others, it's just a matter of making it really clear and crisp do this now, do it for a certain amount of time, and here's what it's worth. Thanks.

MR. ORSINI: Hi there, Commissioners, thanks for having us. My name's Lawrence Orsini. I'm the CEO of LO3 Energy. So, LO3 is building a block chain-based transactive energy platform. So, I'm pretty sure the gentleman from The Brattle Group was talking about a couple of our projects that we've got going around the globe.

The purpose of the platform is really to make a transactive marketplace, to trade megawatts, megawatts demand, and make choices, for consumers to make choices about what kind of energy they want to buy from whom, at what point.

So, a little bit about my company and team. So, about half the team has been in the energy industry for most of their careers. In fact, a good chunk of our team has worked on utility programs here, in California, with the California IOUs for many years.

The rest of the tech team is really focused on hardware, software, and block chain technology. But really, towards the focus of pushing technology through an adoption curve.

So, it became clear to me several years ago that we have the technology already. The batteries, the control systems, the controllable devices to already create a transactive marketplace.

What we don't have is an efficient way to trade the value of that device control. So, that's why we're focused on building this platform. You know about this.

The thing that I would say is this is not just the U.S., this is not just California. Germany has these very same problems. Australia has these problems in spades. They're looking at some really significant grid infrastructure problems in the next two to three years, if they don't get to a way to control demand and recognize the value of demand control rapidly.

So, when we moved to develop this platform, a bit of the research that we did was around how consumers are thinking differently about energy. This is a really interesting report from Accenture, done over a number of years, I think ten years, 13,000 participants across the globe. That's a pretty beefy report.

This slide, out of the report, is probably the most telling and really surprised me. So, what it says there is that, you know, almost 50 percent of consumers are ready to buy community-generated, local energy today. Not in five years. Not in the future, but today.

The more important thing is that 70 percent of these people are ready to participate in energy markets today. Again, not in five years, they want to do it today.

So, I'd encourage you, if you haven't seen this report, to pick it up and take a look at it.

I can say that since we've launched the platform and actually developed the first few projects and started to people, these numbers really do seem real.

The underlying issue, I think, that's really going to ramp this up, and is really creating some of the problems that we're seeing in Germany and Australia, is consumer choice. Right, so consumers, these technologies are reaching a price point where they're accessible. They're easily accessible.

What we need is an efficient way to integrate them into a utility grid. So, there are significant architecture and structural changes that need to happen to grids and grid architecture in the very near future.

I think the ideas of, you know, of transacting the value of DERs, the way we're looking at it today through these regulatory regimes, that are valuing these things discreetly, probably need to shift pretty significantly if we're going to get to a fast-acting, transactive market.

People don't understand. I mean, we were just talking when we were having our lunch, you have to have an attorney to interpret the demand response program.

The average consumer's not going to do that. They want a very simple marketplace they can understand, where they know the value or they can explore the value of their resource.

One of the bigger problems is that utilities, transmission system operators, distribution system operators are being paid a little bit at odds with what the market needs to see for the grid to evolve to this place.

So, having the benefit of traveling and talking to regulators across the globe, in the last couple of years, some of the more innovative things that I'm hearing from some of the regulators, specifically in the Netherlands, some in Germany, is the idea is that we want to shift the way we pay utilities to develop projects. So that they're not being paid for deploying capital and returns on capital projects, so that they're being paid to make the most efficient, resilient, adaptive utility grid that they possibly can.

So, this is what's happening in New York, through the REV process. They're really looking at how do we restructure the ways that the utilities get compensated? So, it recognizes the reality of these technologies that are rapidly moving into the marketplace.

So, one of the projects, the very first project we started was in Brooklyn, with the Brooklyn Microgrid. this is a combination of virtual and under-development, physical Microgrid in Brooklyn itself. I'm not going to talk in too much detail about the project. But I'm going to tell you what the people in Brooklyn really care about.

So, what we're doing in Brooklyn, we've got about 60 meters on distributed energy resources out there, developing a marketplace where we're tokenizing the production of energy, the control of demand and battery storage. And putting on top of those things, on those tokens, values that the community cares about, right.

So, this community cares pretty deeply about circular economy effects. I would much rather buy energy from my neighbor because I know that he's going to take the few dollars a month that I'm paying him and spend it in the community. He's going to buy ice cream cones for the kids and maybe not a boat in Texas somewhere.

They want to do this because they like to know what these resources really cost in their community. They want to see that the environmental impacts happen in their community.

It's really funny, when you explain how the REC market works to a consumer and that you're buying the environmental attribute or the benefit globally of, you know, green energy, but that doesn't accrue here, in your local environment, Brooklynites get really upset, really quick about that. Right, they're paying for something that they don't feel like they're getting.

It's really driving interest in adoption of prosumers. So, people that are participating in the platform are far more interested to install PV, to look at controllable devices, to look at behind-the-meter batteries. Early stages in Brooklyn but, you know, the interest has really been amazing.

And then, this is really pushing more towards community. So, when we start getting down to the grid edge and start talking to real human beings not, you know, people who have been trained to manage very large buildings to a bottom line, you have to bring back a value to them that looks like something they care about. They don't care about kilowatt hours. They don't care about dollars per kilowatt hours. They care about very different things.

So, that's specifically what the platform is meant to help translate.

The platform, itself, like I said it's based on a block chain technology, so it’s a very efficient, distributed, secure way to transfer -- or, to transact value. Right now, Bitcoin, Ethereum(phonetic), and some of the largest exchanges are trading or have market caps in the billions of dollars. This is open source, cryptographically secured hardware that, you know, if you’ve got a billion dollar -- if you have a billion dollar aware on an open source piece of software, you’ve got the entire planet looking at ways to hack it. It hasn’t been done. So, it’s a very secure platform.

This is a demonstration wall. So, what we’re doing in Brooklyn is we’re actually connecting with devices there and allowing people to choose how much they’d be willing to sell the control of their devices for. If I’m a consumer, I want to know two things. I want you to know how much I’m willing to pay for the kind of energy that I want to have and how much I want to have you pay me to turn off my devices. I don’t want you to tell me how much you want to pay me, I want to tell you how much I want you to pay me. And then if you decide you want to pay me for that, we can have a transaction.

We’re in early deployments in several places across the globe. Australia, New York, another in Texas here. We’ve just installed the first few meters here in

Sacramento. We're starting a little deployment here. Most of the interest is coming from Europe.

So, this is an interesting slide. I like this one. This is probably one of the favorites. This is Adriane. Adriane's an actress, she lives in Brooklyn. If you watch Orange is the New Black, she's one of those.

So, Adriane one day said, wait a minute, you know, I bought it. It makes electricity, it puts it on the grid, those are my electrons. So, when I'm sitting in a room with utility guys, one of two things happens. The utilities say -- first, some of them say, well, wait a minute, those are our customers, we need to change the way we're thinking about this.

I think the smart ones, like your CEO at NG say, wait a minute, those are our customers, we need to change the way we think about them.

So, that's what we're trying to do at LO3 Energy.

MR. TAYLOR: Thank you very much, everybody. So, you can see we have a diverse group of industry representatives here. These represent successful business models in the current infrastructure, the current technology, the current policy infrastructure that we have.

So, we have about 40 minutes or so left for this panel. And I'd like to give some time, obviously, for the Commissioners to chime in. I'm going to divide it up into basically two parts.

Let's focus first on the good and then we'll move onto the bad, which is really what we're here to talk about today, right.

So, as we contemplate this is the IEPR process and we're looking at writing the California energy policy for demand response. As recommendations come from joint agencies, it will go out into the public and say here's what California should do.

There are a possibility here that we could take some steps that would maybe harm your businesses, or maybe change some policies that you find beneficial. So, I'd like to go down the line and have everybody identify a policy that you find beneficial to your business. It doesn't have to necessarily be a California policy. But identify a policy that you find beneficial to your business or beneficial just in general.

And let's try to keep these down to one to two minutes each, and then we can move on. I know you're dying to talk about the complaints.

MR. ORSINI: I'd say that there probably isn't one any policy in California. I think California's spent a lot of time figuring how to manage demand response markets and put good incentives in place. It's a kludgy; you need an attorney to interpret it, so it's going to prevent a lot of people from participating in the market. But there has been a significant amount of effort over the years to develop this market in California.

So, the benefit is there are a lot of incentives in place to participate in these markets. I'll stop there and talk about the problems later.

MR. EGGERS: Yeah, I don't know what particular policy to identify. I think the fact that we're doing this and figuring it out is a good thing, and that we've seeded the market and built up companies like all of those that are here, that have technologies is great.

And, you know, my thoughts are generally about ideas about how to fix it, so we'll come back to that.

MR. ANDERSON: As a company, again, that works primarily with residential customers, many of whom don't know much about the energy space or just don't care, there's many other things competing for their time, I'd really like to call attention to the click through process that Bruce Kaneshiro mentioned this morning. And our hope that that will enormously simplify the customer on-boarding process.

This isn't something foreign to most people. You may not realize it, but you've seen this before in other settings. For instance, with services like Facebook or Google, when a third-party service, and I'll use the *New York Times* as an example, wants to access your personal data, that is hosted by a service like Facebook, Facebook prompts you for your user name and password in order for you to authenticate yourself.

This is exactly the same way that this envisioned click through process would work between the utilities and third-party demand response providers. So, it's nothing new to customers.

With that in mind I do want to just quickly say, and Bruce alluded to this as well, we're not out of the woods just when we get through this authentication and authorization process. That's really only the beginning of an ongoing and we hope long-term relationship that involves the third-party provider, the customer, and the utility.

And unfortunately in our experience to date, with tens of thousands of customers in California, we've seen a lot of issues with ongoing data exchange with the utilities. We have seen days on which we suddenly receive no interval meter data for any user when, previously, we were getting data for tens of thousands of users.

We see customer authorizations that inexplicably terminate and we altogether stop receiving a customer's data.

We see customers with a CCA, who we get no historical meter data for them and we can't compute baselines dating back several weeks.

We also see data that we received from the utility that does not match the data that the customer sees when they sign in their utility portal.

Something's going wrong in the process of collecting that data and sending it over to the third-party.

This presents a number of challenges. One of them is this cash flow problem that Commissioner McAllister identified. It potentially places us at risk of not being able to comply with the ISO's tariff requirements for meter data submission.

I believe that the drop dead deadline is something like 48 business days after the fact. Now, fortunately, in most cases, we've been able to meet that.

But ask yourself as a customer if 48 business days is good enough for getting feedback on your demand response performance. The LBNL Study identified timely feedback as one of the most important things that can be provided to customers to help them improve their performance.

Imagine if I picked up my smart phone and I checked the news, and the best I can see news from two months ago, if I'm only finding out now that the U.S. has withdrawn from the Paris Climate Accord, for instance. Or, the best I can see is sports scores from one month ago, or my stocks from one month ago. That's not a good customer experience.

Customers need timely feedback. They deserve timely feedback.

I would encourage the Commissions to continue to work with the utilities and third-parties to make sure that these data exchange processes work as well as possible.

CHAIR WEISENMILLER: No, I would say in the past I've testified on utility billing system stuff and, indeed, testified for major disallowances.

But I think your analogy is facile. You're not talking -- you're talking more about Amazon connecting. And the utility billing system is sort of keystone to all of their stuff. It's not like, okay, can I link into your Facebook page? It might be more like can I link into your Amazon account and see what's going on.

You know, I'd say it's pretty sensitive information. It's important they get on their toes. But again, they've got to make sure that that doesn't blow up in terms of hacking or whatever.

MR. ANDERSON: Sure. And to be clear, I'm not advocating for any disclosure of information that isn't authorized by the customer. What I'm simply saying is once the customer has provided an authorization, to the extent that we can provide that customer's information to the service provider as quickly as possible, and thereby allow feedback to be provided to the customer as quickly as possible, that will be extremely valuable.

And as one example, in the case of Con Edison in New York, it's my understanding they have committed to provide data to third-parties, who have been authorized with data access, customer data within 30 minutes, so that they can provide timely feedback.

MR. ORSINI: Just a quick response here. So, a couple of thoughts. First off, in Germany, they've separated the transmission system operators, utilities, and now they have a new class which are meter installation utilities -- not utilities, but installers.

In Australia, every retailer installs their own meter. The data goes to the retailer.

So, I get that it works this way in California, but it's shifting quickly in other places around the world. In fact --

CHAIR WEISENMILLER: But Germany doesn't have AMI. Germany has 900 distribution companies, some of which are your local cities. So, again, you've got to dig into these things carefully.

MR. ORSINI: Yeah, Germany is actually installing AMI, so that's --

CHAIR WEISENMILLER: Well, I know they're doing it now, but they don't -- it's not there, now. They're trying to get serious on the energy efficiency side, but it wasn't like they did it ten years ago.

MR. ORSINI: Fair enough.

MS. KENNEDY: I think the single most important policy that's underway right now is the bifurcation of the DR resources and the supply and load modifying, that the PUC undertook several years ago, and is just now coming into fruition.

The second is the integration of those supply side demand response resources into the CAISO wholesale market.

And the third is the very nascent efforts to integrate demand response, distributed generation, and energy efficiency customer incentives into one demand side management bucket.

The three of those, together, will transform demand side management.

MR. PANZER: You know, I think it's a good transition from what Susan just said. You know, from our stand point we're really focused on, you know, how do we motivate customers, especially since we're so focused on such a hard-to-reach customer for the utilities and really engaging with the customers for the utilities? It's all about trying to drive more holistic solutions.

Over time we want to, you know, really create a framework that allows us to think about all different products and services, you know, well beyond just the EE, or DR, or storage but, you know, electric vehicles and so on and so forth. You know, and think about how to apply them and bring them to the customers more holistically.

But, you know, I mean right now thinking about things in a world of just EE and DR is important because, you know, for a long time we just thought about EE or we just thought about DR. And really what we're seeing, especially as we're trying to drive the small to medium business market is that EE is actually paying for the DR.

And, you know, the way that we're actually able to motivate customers, again, is bringing this integrated solution that includes financing, as well, and doesn't, you know, push any of the responsibility off to the customer to actually have to pay for it, or move forward on their own.

And the way that we're able to pay off the financing is heavily driven through the energy efficiency. And once we go off and we actually apply the energy efficiency, it just becomes a no-brainer just to put the DR in, as well.

And so, it's really important for us to really start thinking holistically for the customers. And, you know, once we really focus on what's actually going to drive the customer, and what's going to get them to say yes, and how we can make it easier on them, then it allows us, you know, on this side of the equation, not on the customer side of the equation, to start thinking about how do we apply these to different scenarios?

And so, really, we just are focused so heavily on customer adoption, driving the market around customer adoption, and then us working with all of these other institutions, and all these other stakeholders to really, you know, figure out how to make everything work out on the other side.

CPUC COMMISSIONER GUZMAN ACEVES: Maybe this is more for the residential side, but I didn't hear you mention time of use as one of those tools in the package. And is time of use in a way maybe too stagnant, particularly because of our delayed process, and shifting the time periods to adjust to what's really happening in any given territory?

And do we need something more dynamic? Does it help you at all or does it really hinder you in a way that it kind of takes away, maybe, part of your savings?

MR. PANZER: I think for us, you know, just having very clear rules is helpful enough. I mean, time of use is just -- we'll respond to whatever sorts of design is set up around time of use. It's just making it -- we were talking about this at lunch, just making it as simple as possible, you know, and just trying to set some frameworks in place that --

CPUC COMMISSIONER GUZMAN ACEVES: Right. I guess from your perspective, in terms of the customer benefit, you know, if we're -- because it could be particularly -- it could be not a reward.

MR. PANZER: Well, yeah, I mean -- I mean, again, from our stand point, since we go off and we lock in the customer's bill for the foreseeable future, while we pay off this financing mechanism, we're setting them at a certain rate that is lower than what their existing average monthly bill was prior to actually implementing the project. And everything else is on us to figure out how do we actually make money, now?

You know, we look at energy efficiency, again, as the driver to pay this off. But, you know, if we can make more money on projects through the course of the year through demand response, or through really working through the time of use side of it, we just look at that as a bonus pool. And then, at the end of the year, if there's enough bonus added up, we're going to provide that back to the customer.

But overall, they're already starting from a beneficial place. They've got new equipment and somebody else is managing this for them and they are paying a lower bill.

MR. EGGERS: I'd say we're evolving to a place where software is running buildings. And software can respond very quickly and very well to clear price signals. Whether there actually is no demand response programs, as one of the speaker said earlier, it's just a real-time market price, maybe it's an hour-ahead market price, software can respond to that. And building owners can make the decisions ahead of time, like I showed before, that if this price signal is X, we are going to do Y, and respond to that instantaneously, in real time.

Software can't respond to auctions and regulatory folks, and legal folks that have to figure out new programs, and read large dockets, and so forth. It can't do that. But if there are clear signals ahead of time it's going to cost you this much, and save you this much to do X, the buildings will respond because the software will do it.

MR. TAYLOR: Susan?

MS. KENNEDY: I would say, today, the time of use is a double-edged sword. In the load-modifying resource world, if time-of-use rates are high enough to incentivize consumers to change their behavior and move off grid during the peak period, then they're pretty punishingly high, number one. And you're incentivizing the customer to put in distributed load technology that allows them to really get off the grid.

Then, you've taken the resources away from the utility, because the time-of-use rates are not designed for customer behavior, they're designed for cost recovery, for the system costs.

And so, the more effective the time-of-use rates are, the more you're actually hurting the revenues to the utilities and you're flattening out the system cost and the system load, so you've lost the benefit of time of use.

On the C&I side, you know, customers are already facing the economics where putting in distributed generation, whether it's fuel cells, micro turbines, solar PV, and other technologies, and now storage, where the more you put in facilities' demand charges, and time of use, real-time pricing, you know, peak pricing, the more you've created the economic incentive for them to get off peak and put in these distributed technologies. So, the utilities keep having to change their price signals to get the cost recovery.

So, rationalizing the rate design around what you're trying to achieve with load-modifying resources, with the rate recovery that's necessary for maintaining the system on the utility side is critical.

On the supply side demand response treat it differently. Where you get the reward is when you're paying a large customer to install the technology that allows them to move their load around without having to shut things off.

Right now, a lot of the largest load customers are using either gas or diesel if they're going to shift a lot of load, right. So, if you want them to really respond to demand response in a large way, you have to make the economics beneficial to them to be able to install the technology that allows them to respond without the economic pain of having to shut things down.

MR. ORSINI: Yeah, just one last thought. So, I think time of use has been a really good half-step towards where we really need to go, but it doesn't -- it has a hard time reflecting real-time grid issues.

So, I know in Spain, Iberdrola, they've gone to real-time pricing. And there's some real concern for utilities that if you go to some of these pricing models that you're going to really diminish some of the values that utilities count on. But it builds a value stack for consumers then to make different choices.

And in fact, Iberdrola and the utility there has actually put together another set of services, where they're actually buying the risk of those real-time markets and offering a fixed fee, sort of like a cellular plan product, where they're absorbing the cost of that risk.

But the majority of people have actually adapted pretty nicely to those real-time prices.

MR. ANDERSON: Very quickly, again, from the residential perspective. I think OhmConnect and other third-party DRPs have presented a set of solutions that could help manage the transition for many customers to

TOU rates, especially customers in the low-income community.

We heard from others this morning how there's a perception that folks in this community are likely to be harmed by TOU and need to be protected from the adverse implications of TOU.

I think what we're doing by educating customers about the time value of energy, helping them get enabling technology into their homes at low cost, helping them understand where their energy comes from and how they use it will only serve to help them manage TOU rates in the future.

And we have many users in our user base that are low-income, that are our CARE customers. And I think we're taking steps to help empower these people and not treat them with a purely paternalistic attitude.

CHAIR WEISENMILLER: Yeah, actually, it might help if each of you indicate whether your focus is residential or C&I, or all of the above. Since you're incentives or your risk model could be different.

MR. TAYLOR: Yeah, we have a cross-section here, so I'll start with --

MR. PANZER: C&I with a focus on SMV, in particular.

MS. KENNEDY: C&I with a focus on very large commercial/industrial.

MR. ANDERSON: Predominantly residential, but some small commercial.

MR. EGGERS: Medium and large commercial.

MR. ORSINI: It's a platform, so it's all of the above.

MR. TAYLOR: So, I know each of you have some concerns and some recommendations for the Commissioners, for our California policy document.

Do we have a volunteer to go first or should we just go down the line? Aaron, are you ready?

MR. PANZER: Yeah, happy to. You know, I mean we were talking at lunch about data and it's always an interesting topic. And, you know, as we were talking it's funny because there are so many different areas throughout the process that data is actually applied.

And, you know, I'll talk about it more from the context of when we start to think about things from a programmatic stand point.

You know, when we designed this solution, we looked at it and said, you know, in order to move the customers forward, especially since we're going after the small to medium business market, we need to make sure that our process is very lean. I mean, any sorts of customizations, any sorts of extra costs embedded in the process could kill the entire process of actually acquiring any customers.

And so, what we've done is we've programmatized the whole thing and said, let's go to the utilities and let's basically offer this as a program that we're going to drive their customers to both EE and DR programs, and really try to move the market in that way.

The way that we're able to do this is leveraging our data analytics platform, our retro-efficiency analytics platform that allows us to be able to take a population of buildings and figure out who are the customers that we should actually go after and why.

And then, once we have that information, we can go off and we can engage the customers in a capacity where we're actually already informed of, you know, you are this customer. This is what your building performance looks like and these are the opportunities to improve upon it. It's a much better start to the conversation as opposed to say, you know, let's look inside your building.

And it also reduces the costs because we can start to engage them remotely, as opposed to having to go and knock on every single door.

And by making it a utility program, we're also able to bring the utility brand to the equation. Which, admittedly, most people throughout -- our first program is being run in the Central Valley. You know, most people in the Central Valley don’t know who Ecova is. They know who PG&E is, though. And so, you know, that’s all great.

Now, as we start to look at, you know, the transition to more market-based frameworks, like DRAM as opposed to DR programs, you know, that creates a situation of where it’s less of program implementers and more of aggregators.

And, you know, and basically what’s lost in that transition is the ability to get access to that population data, so that you can drive down the costs in the process and really figure out who you should engage with, and really drive down the cost of the customer acquisition, which is huge, especially engaging in this market.

MS. KENNEDY: I would say aligning the supply side demand response programs with the CAISO wholesale market is the most challenging and the most important. Without those being aligned, the value proposition is not going to be there for the end-use customer, and you won’t be able to sign customers up.

And so, to date, if you’re a behind-the-meter resource, a supply side demand resources, you have three options. You can be traded in the wholesale market as a proxy demand response, in which case you're stuck with the energy baseline, which will destroy the industry because it's simply inaccurate to use the energy baseline, and it destroys probably 25 percent of the revenue availability from the value proposition of the end-use customers.

For a reliability demand response product, in which case the programs, the retail programs are designed today, they're actually paying customers to keep their peak high and to not participate in any other demand response programs. So, you can't really dual participate very easily.

The second -- I mean, the third is a non-generating resource, which the behind-the-meter resource has not yet qualified as an NGR, and so the program wasn't -- they didn't necessarily think about it when they designed it, it's not eligible for RA, yet. I believe it is. I believe that is a technical issue that will be done.

But, yet, you have to think about behind-the-meter supply side resources and make sure that they are aligned with the wholesale market rules in order to create the value proposition.

MR. ANDERSON: Bruce, from the CPUC, spoke this morning about the Commission's recently adopted overarching goal for demand response, as well as a series of principles for demand response. And this goal and these principles concern things like fair competition, customer choice, preference for third-party services, and lower overall cost to customers.

As again, a third-party competing in this market, and one that serves predominantly residential customers, who are less savvy, arguably, about their energy costs and needs than are commercial and industrial customers, we continue to have concerns about the ability to compete fairly with established utility programs.

And one of these really stems from asymmetric access to customer data. The utilities, by virtue of being providers of energy to end-use customers, and the meter data management agents to the customers, have access to a universe data that we can't access at all. Or, if we can access it, we can only do so after receiving customer consent.

And getting that customer consent is not an easy or a costless thing, as Aaron just suggested. We need to typically incur costs of marketing to customers before we can even get their data, before we can even ascertain whether or not they are good candidates for demand response.

So, we are at a disadvantage in terms of marketing our services to customers in an industry where there's already relatively low overall customer awareness of demand response options to begin with.

It's my opinion that most customers don't know that they can get paid for reducing energy at times when that's valuable to the grid. And if they do know, their first thought is probably going to be, of course, that's something I do with my utility, not something I do with a third-party company.

Now, we recognize it's not a feasible solution to make all of that data available to any old company. There's obviously confidentiality, and privacy issues, and legality issues surrounding that. But there has to be another way to address that asymmetry, that competitive asymmetry.

And one thing we think that the IOUs could do, along with the Commissions, is to do a better job of promoting overall awareness among customers of all of the DR options. To socialize the customers what DR is. Why it's important. Why it's valuable and how they can benefit. And, most importantly, the customers have a choice of who they're going to provide DR with.

If they want to provide DR with their utility if that's the best fit for them, then terrific.

But they should know that they have other options that they can go out and learn about.

We don't think it's suitable for the IOUs to promote any one third-party option, but they should be doing more to generate overall awareness because that's, at the end of the day, going to benefit all ratepayers.

COMMISSIONER MCALLISTER: Well, I just want to ask a quick follow up. So, is there -- so, I agree with what you said. I guess, so is there a role for the PUC, or some standards, or this looks like a potential market failure? Is there a role, you know, think about what needs to be done in order to sort of fix that market failure.

MR. ANDERSON: Sure. OhmConnect, and I believe some other demand response entities have proposed in the 2018 to 2022 DR applications proceeding that the utilities establish something of an online portal or marketplace on their websites that would present basic information about all of the options available to customers. So, the name of a program, a basic description, a link to that program website. Simply presenting customers with information in one place that they can use to make a decision.

Now, we've received some positive feedback from the utilities about the establishment of such a webpage. However, we believe it's very important that that webpage, or portal, or whatever you want to call it, is actively marketed to customers. That if it just sits there on the website, people aren't going to find it, people aren't going to take any action.

To paraphrase the famous movie, *Dr. Strangelove*, "The whole point is lost if you keep the thing secret. You need to tell the world."

So, the utilities have suggested, perhaps, that this activity makes sense, but perhaps it's best undertaken in a broader proceeding, in the AB 793 proceeding, the Energy Upgrade California proceeding.

Our counter argument would be that at this time we still think it needs dedicated attention. Demand response doesn't have the same recognition, the same customer awareness that something like energy efficiency does.

I believe we heard Commissioner Douglas say something to this effect in her opening remarks. That energy efficiency has received some mainstream recognition and she would like to see demand response achieve the same, as would we.

But we think it's going to take some time and it's going to take some nurturing. And that it makes sense to focus resources specifically on demand response until it achieves more wide stream recognition.

MR. EGGERS: So, my comments are related to medium and large commercial office, retail, light industrial kinds of buildings. And I'd say, as more and more buildings get connected with sophisticated software systems that can easily respond to signals, they'll do what we the signals tell them to. And, you know, that's both a good thing and bad thing.

And I think we have to be really careful that if what we want to do is shape loads in a certain way, then we should give them clear signals to shape those loads in that way and they'll respond to those signals.

I think with the DRAM program accepted, today the programs are too complicated and the signals aren't necessarily clear and they change a lot.

So, I talked to three before coming here. Over the last week or two I talked to three of our large customers that have somewhere between 5, 10, 15 million square feet of commercial real estate, a bunch of which is connected to intelligent HVAC and lighting management systems.

One of which participates a lot in demand response, and the other two don't even though they could. And they said, it's too complicated, we don't know what we're going to get paid, and we're a little bit worried about, obviously, customer discomfort. And if the incentives were higher, we're willing to push that a little bit further. But the incentives aren't quite there right now, in most cases, for them.

But if what you're really concerned about is shaping loads, there's more that could be done to do that. Right now, you know, it's really just curtailment, but we could do all kinds of things with HVAC systems in larger buildings to shift load. And it's just that's not being paid for enough to make it happen right now.

So, I guess that's kind of my second comment is pay for the load shapes that you want.

And, finally, I think the proposal to integrate EE and DR that was discussed earlier is a great idea. The same technologies, like ours and many others, can perform both. We're hooked into the building. You know, we can make almost anything happen, whether it's EE or DR.

So, incentives that make that happen are great for both. Connecting all of that technology is good for both.

And, finally, you know, there's perverse incentives. There are things that we do in the name of

EE that make the duck curve worse. So, those things really need to be planned together.

And we do it because it saves our clients money, but, you know, it's probably -- if was king for a day, we probably wouldn't be doing it. But that's the way the incentives are set up.

CHAIR WEISENMILLER: If we had better rate design.

MR. EGGERS: Sorry?

CHAIR WEISENMILLER: If we had better rate design.

MR. EGGERS: A better rate design, right. If I was king for a day, we'd have better rate design.

COMMISSIONER MCALLISTER: I think you'd need a magic wand, actually.

MR. EGGERS: I would. All right, if I was a sorcerer.

MR. ORSINI: So, I'd say California has already done a stellar job of buying all the cost-effective demand response. Given the way that the participation has started to plateau, I think you've kind of reached a point where the market has recognized the value of the incentives versus the costs and the value to the consumer, of demand response.

In order to get over that hump, I think you really need to look a location-based, real-time pricing models that recognize that cost and value, not only of the commodity, but the infrastructure.

So, paying to use the infrastructure, between myself and a generator, needs to be a thing of the future, right.

Using that model, you can price into congestion. You can actually price demand into congestion where it exists. Not as a blanket across large swaths of the grid.

I think that really we're at a point where to get deeper into demand response, we're going to have to start engaging a different layer of customer. So, consumers need to be enabled in these markets. They need to have choice for fuel source. They need to have choice for who they buy from, when they buy from.

Until we get to a place where consumers can actually participate in this market, it's going to get -- it will be, from an incentive perspective, far more expensive to get to that market.

But I think if we do it well and we engage these consumers, they'll pick up part of the cost of doing some of these -- or, actually, installing some of the infrastructure to do these things.

I would encourage you to look at some of the non-wires projects, like the Brooklyn/Queens Demand Management Project. Some of the projects that are happening in Europe where you're actually -- they're forcing the utilities to look first at deploying capital in technologies like these to offset grid infrastructure projects, to reduce the cost of gold-plating the grid, is what they call it in Germany.

If you can use those monies and distribute to the people, in the places where we have the problems, it makes for a far more economically efficient grid, as well as a far more stable and resilient grid.

So, in order to get there, you have to build in the full value stack of energy. So, not just the commodity costs, but building in that full value stack so that you can recognize the full cost and the full benefit, as a consumer, on a utility grid, here in California.

And I'd say, you know, back to the meter point, I think meters are going to be a consumer device in the next five years. I think Australia's going to push it into the hands of consumers. Germany will reconsider, very quickly. Europe will probably follow suit. We should start thinking along those lines.

I know utilities have built their business models around them. That's part of the problem. So, unwinding those business models from the meter and the meter data, and actually putting some of that control back in consumers' hands are going to solve, in my opinion, some of the significant problems that we're looking at for grids.

MS. KENNEDY: Can I add a couple since --

CHAIR WEISENMILLER: That's fine.

MS. KENNEDY: For the CEC, you've got a lot of opportunity with EPIC funding to promote the installation of integrated systems that combine demand response and energy efficiency. I think all demand response and resource programs should be looked at through the lens of efficiency. And right now it's Balkanized and it's bifurcated.

The CPUC is in the same position. You've got all these programs that are very technology-specific. Permanent load shifting was designed for thermal energy storage, not battery storage. And, yet, it's probably one of the single most important buckets of funding that could be available today to install these technologies.

Auto demand response was designed for software. Instead of an integrated system that combines battery-backed demand response, with some of the DR programs that are out there. And there's limitations on the use of ADR funds.

For the CAISO, you've got -- I think one of the biggest challenges is you've got the one service account, one program, one resource ID problem. And when you're talking about demand side management and very expensive load control technologies you have to do revenue stacking. So, you need to be able to provide multiple resources behind one resource ID. And that's going to be a challenge.

If I have a 4-megawatt load, I can put in two and a half megawatts of batteries, and I can do demand response in one type of a bucket, and I can also do an NGR with a battery from a different -- I mean, in other words, I can provide two different resources, empirically measured from one resource. But if the resource ID says one customer load, one service account, one thing, I can't provide multiple resources. So, that's a technical challenge.

But again, in order to be able to tap into the real value of a customer that's going to harness their load and provide it for revenues, these are the technical challenges that you have to figure out in order to enable that customer to participate.

CHAIR WEISENMILLER: Yeah, I was just going to say it's time to transition over.

The first thing I was going to note was, obviously, one of the things that the Carter legislation did was introduce economics more into regulation and rate design. But also, with PURPA, the real intent was to bring some creativity into the utilities, in the generation area.

And so, I think one of the things we're struggling with here is getting more creativity in the demand response programs.

It does seem, although you all have a different lens in a way that, you know, having said we've gone from looking at DER down to demand response, really focusing on it, that part of it is saying that we really have to reach across the silos. You know, that there's an energy efficiency program, or there's a storage program or, you know. Just all the stuff behind the meter in some ways and, again, maybe demand response isn't the sexiest piece of that. But in terms of looking at it -- and, again, I'm still struggling with how big -- you know, I assume if you say everything that's behind the meter is going to be one program at the PUC, then it's probably mind numbing.

At the same time, you know, it doesn't seem like demand response, per se, is going to drive things.

So, again, trying to get people to think a little bit about what's the optimal combination.

Now, part of reality might be that we need to let all of you have your different business models, and some of you are going to go splat and others are going to grow gigantic, depending upon what the right mixture is.

But certainly trying to think about, you know, as I said, as regulators we approach things, and it may not be the best approach or the programs across the market, so trying to understand that.

And then, the final thing is certainly to give people -- consumer protection. The one thing is that, you know, people -- as my 91-year-old dad has dealt with one utility for 70 years, it doesn't matter what options are there, you know. At this stage in life he's going to continue. But again, it's pretty safe.

So, as you're looking for more and more access or, you know, competitive markets there, obviously part of the challenge for regulators is consumer protection, at least for the less sophisticated clients, you know.

So, certainly, some thinking about what is the optimal configurations and how do we handle the consumer protection issues other than saying, yeah, the Attorney General's going to sue you at some point. Or, you know, the PUC's going to step in and say we're going to do a very rigid -- you know, these are the qualifications you're going to need to have to serve people in California.

MR. PANZER: I think, you know, a couple of things. On the last point, on the data side, you know, I mean I would encourage continued rigorous third-party security reviews of entities like ours. You know, I mean as I mentioned the movement to market-based solutions.

And also, you know, I mean if we're looking at like, you know, providing population data to third parties, I think that, you know, I mean the utilities, the ratepayers have really paid for all that AMI infrastructure. And I think that there's a business case to be made that we should be paying for that data.

If it moves to exclusively to more of a market-based model, and we want to get access to that data, why not, you know?

A couple of points that I noted from colleagues over here is, you know, it seems like the notion of getting controllable loads out there on the grid is enormously important. And so, I think that's huge when we start to think about really integrating all of these solutions together, and thinking about them more holistically.

And for the customer, we really have to think about them more holistically because we need to be able to go off and say for this customer what's the best set of solutions. And then, as a vendor, think about it from the grid stand point and think about what's going to provide the most value back to the grid, so we can figure out how much we can get paid as a third-party, and provide some of that back into the projects that we're going to actually provide to the customers. And so, we definitely have to think more holistically.

The other point that I'll make, a little bit off topic from that, but I've heard about making DR a sexier term or, you know, really marketing it more. We don't talk about DR when we go to our customers. You know, it's confusing. We don't want to talk about DR. We want to talk about comfort. We want to talk about saving them money and comfort. We don't want to confuse them. The moment we start talking about DR, we've lost the customer.

MS. KENNEDY: That's not true for the C&I. I mean it's the --

COMMISSIONER MCALLISTER: Exactly.

MS. KENNEDY: Yeah, I mean even though it's all about the value propositions. I mean, we're taking money from the end-use customer, and then giving it back to them to encourage them not to use energy. You know, and we were telling the utilities, we're taking the money from the customer and telling the utilities to go buy all the resources to serve those customers, and then we're giving them money to tell them not to use the energy.

The customers, they're value proposition is upside down in terms of what -- you've got to make the customers part of the solution. The C&I customers, they love the idea of demand response, as long as they're getting paid for it. Because right now, the value proposition on demand response is not high enough. Right.

Energy efficiency, the ROI on energy efficiency is a well-work path of -- you know, how do you -- it has to pay for itself within a certain number of one, two, three years, or else they don't invest in the energy efficiency.

When you combine demand response that is properly incentivized, with energy efficiency, the value proposition to the end-use customer starts to get into the money in terms of being able to incentivize them to install very expensive technology.

My colleagues here are all in the demand response world that has to keep their CAPEX very low. That's the only way you make the economics work, right.

So, if you want to make DR sexy and make it part of a grid solution, you have to be able to scale it. That means you need load control technology so they don't have to turn off their air conditioners. I mean, we share a client with the Irvine Company. And our battery systems are designed to lay on top of the demand response that they currently do and allow them to go deeper into the load, and be able to use it multiple times a day, and respond in 20 minutes, instead of a day-ahead signal.

So, these are complementary technology. Software that operates the building load and battery that allows them to actually quadruple their participation in demand response.

So, putting them together is critical.

CHAIR WEISENMILLER: Yeah, but does that mean the Commission has to combine not only EE and DR, but also storage in a single program?

MS. KENNEDY: But a piece of Tupperware. Okay, nobody wants batteries. That's the mystery of energy storage. Nobody wants batteries. They want energy savings, they want reliability, and they want revenues from whatever they're participating in. That's all that matters.

And so, I think the biggest mistake we've made to date is that we've put storage in a bucket as if somebody's buying batteries, right?

We had to fight at almost every level to combine, you know, a resource adequacy product that the utility is buying with an extra-large set of batteries that the SGIP is -- that the customer is using SGIP to install here, with getting auto demand response incentives to that, so that load was available in a demand response program.

Because everybody looked at that and said, whoa, whoa, whoa, you're triple dipping here. Like, no, we're not. This is a six-hour battery system, and it's very, very expensive and the customer's going to use that load to participate in both the resource adequacy, and they're going to do permanent load shifting, peak demand management. You know, the utilities and the regulators are all looking at it in the siloed buckets, based upon the technology in which those programs were born. So, battery is a stem cell, it can be anything.

And I think energy efficiency, looking at all of those programs through the lens of energy efficiency is critical to the success of the program.

MR. EGGERS: Yeah, and similarly with our software system they can do all these different things.

Originally, we didn't sell it as a demand management. As opposed to DR, when you get the signal from a utility, you're signed up in the program, you know, and you do your thing.

And our clients just started free-wheeling and say like, oh, well, when we had that demand response event, we were fiddling with the software to save this much energy and now we're doing it every day. It's just the exact same tools that they use, and they can shape the load any way they want to shape it, depending on what the signal is. And they don't care whether it's a demand response payment that's paying them to do it, it's a demand charge that's forcing them to do it, it's a battery that's getting to do it. It's just I'm going to pay this much money for this much kilowatt hours used and kW hit over the next hour. And I've got a whole bunch of software, and batteries, and other things that can help me shape the load, however those incentives tell me to shape it.

MS. KENNEDY: These guys are transformational. I mean, they told - -the Irvine Company told us they were getting out of their demand response programs because the weather patterns in Southern California were having them be called of the time. And they couldn't afford to have their HVAC systems running at -- you know, making their tenants so uncomfortable. And so, they were starting to back off of their commitment, or they were planning to, anyway.

And what the batteries allow them to do is now manage both their costs and their participation. It wildly increased their participation without the pain of having to turn off their air conditioning.

And they're very sophisticated energy consumers, so they're investing in energy efficiency, and in state-of-the-art demand control. The batteries are complementary in that respect. So, I think it's the -- so, batteries combined with traditional demand response load control software is the savior of demand response.

MR. ANDERSON: It's worth repeating as well, I think, one of the principles in that decision from September that Bruce mentioned, and that I mentioned as well, concerns technology agnosticism. So, what matters is what happens at the meter and not what's happening behind the meter.

MR. ORSINI: It really boils down to prices to devices. Once you get the price to a device, then the market can respond to that price, a consumer can respond to that price. The guy who manages fleets of buildings can respond to that device.

When you hide it behind a rate structure that prevents you from seeing that real price, you can't respond to that.

MS. KENNEDY: Or, if the price is not high enough, I mean the price is not appropriate.

MR. EGGERS: Oh, yeah, the price has to be transparent and clear, and reasonable.

CHAIR WEISENMILLER: Okay. Well, we're sort of going to be wrapping up. I want to make sure that Keith -- anyway, everyone here has a chance and then we're going to have to move on to the next one so we're not here all night. Thanks. We could. We could be. I mean, this is a pretty interesting conversation. Andrew might stick around.

(Laughter)

MR. CASEY: Okay, great panel. Very encouraging, inspirational. But the one thing I'm really struggling with is what's it going to take for these technologies to take off? You've talked about the value stack that you have, but I'm still not clear on what the revenue stack is.

I mean, what's your bread and butter for a revenue source and how do we really shine a light on that, and really get it take off?

Because you've got utility funding, whether it's the utility is an LSE, or is a wires company. You have the customer, the customer benefits from this, presumably their source of revenue. And, obviously, you have the ISO markets.

But I mean what do you see as your bread and butter and how do we get it to really take off as a marketplace for this stuff?

MR. TAYLOR: Let's just go down, quickly.

MR. ORSINI: Yeah. Yeah, I would say, once we get the prices to the devices, then consumers are enabled to do choice. If I can do something new, then that's something of value to me. So, money can flow into that value equation without building a full stack of that value, incorporating distribution, transmission cost, all the way down to the grid edge, then I never see that. So, as soon as that's in place customers can respond and we can respond.

MR. EGGERS: We've got about roughly 300 buildings connected to the software system that I showed today. So, it's far from what I'd like it to be, but it's a substantial amount, tens of millions of square feet.

And what would that take for me say it's 3,000 here, in three years, maybe that's your question. You know, 300 is nice, but it's kind of just getting started.

And what's driving it today is mostly energy efficiency. Our customers are using it to reduce their kWh and to shape the load a little bit to reduce demand charges.

So, what's it going to take to get more people to do that, it's rate reform is a big piece of it. Especially, if you were -- today, we're focused on more of the load shaping and load shifting. Just to make it clear and easy, and make it worth it. If it's worth it to the grid, if you're here it must be costing the grid a lot of money, right? That's why we're all talking about this. So, pass that through to consumers.

And I've never heard that catch phrase before, but the folks at Irvine, and Kilroy, and Shorenstein, and so forth, if it's worth it to them, they'll respond. They'll run the chiller a little bit more or our software will respond to that signal and run the chiller a little bit more from 12:00 to 1:00, and then coast. And we can coast for hours. Instead, right now, we're doing the opposite or we're making that duck curve worse because that's what the incentive is telling us to do.

CPUC COMMISSIONER GUZMAN ACEVES: (Off mic)

MR. EGGERS: Sorry, I didn't understand the question.

CPUC COMMISSIONER GUZMAN ACEVES: Sorry. Outside of your EE investments, the real value is the participation in the ISO market?

MR. EGGERS: I guess, outside of the EE, the value -- I'm still not sure I understand the question, but I think I do.

The value is that the ISO just -- we need a price signal to do --

CPUC COMMISSIONER GUZMAN ACEVES: From the ISO.

MR. EGGERS: Yeah, from the ISO, that makes it clear what you want them to do. And with connected buildings, they can respond quickly and easily. And this is actually in combination with storage, but even without storage.

COMMISSIONER MCALLISTER: I mean, the common theme seems to be -- I mean, this is great because I mean it's very inspiring. I agree with Keith. I mean, this stuff can respond to whatever we throw out at, right, so what we need to do is throw the right things at it so that the grid gets what it needs, right?

But there's a lot -- and whether that -- you know, the rate design is what it is, and they're all doing arbitrage on behalf of their customer, and managing their load behind the meter.

MR. EGGERS: That's right.

COMMISSIONER MCALLISTER: But that rate, it just kind of is what it is and doesn't necessarily have anything to do with what the grid actually needs or not.

CPUC COMMISSIONER GUZMAN ACEVES: Well, we're talking about rates interchangeably. I mean, we deal with a lot of, you know, I guess demand side rates. And you're talking about a supply side rate. That's --

COMMISSIONER MCALLISTER: No, no, no, he's talking about a retail rate.

MR. EGGERS: Yeah, I'm talking about --

COMMISSIONER MCALLISTER: He's managing a building with a retail rate.

MR. EGGERS: Yeah, so my customers are the chief engineers, and the property managers that are running the 500,000 square foot office buildings, and shopping malls, and so forth. And they can't figure out the complexity of, you know, tariffs, and changing demand response programs and so forth.

But we can program in, if you want less power used at 4:00 p.m., and you give us a rate that is incentive to do that, we can put it in the software and it's crisp and clear, and it's worth it to them to use more power before or after, the software will make it happen.

COMMISSIONER MCALLISTER: And I think what you're saying is that you're basically focused on doing right for your customer based on that rate.

MR. EGGERS: Based on that rate.

COMMISSIONER MCALLISTER: And there are other things you could do to create another cash flow stream, but it’s kind of just not worth it because it’s too complex.

MR. EGGERS: That’s right.

COMMISSIONER MCALLISTER: Right. So, what we need to do is enable those streams and give them a value that enables that stack to exist, and that proposition, that value proposition, that business model to be more and more viable so you can have 3,000 buildings, and not just 300 buildings.

MR. EGGERS: That’s correct.

COMMISSIONER MCALLISTER: At least that’s just kind of my takeaway here.

MR. EGGERS: Yeah. And in the meantime, with scheduling and energy efficiency technology, we’ll continue to grow the business. But there’s an opportunity for us to do more to help fix the shape of the curve.

COMMISSIONER MCALLISTER: Yeah, so you guys wanted to keep going down the line.

MR. TAYLOR: Any other responses to Mr. Casey?

MR. ANDERSON: Yes, quickly. As Mona from EnerNOC indicated earlier this morning, for those third-party DRPs, at least those that are not predominantly storage entities, the demand response auction mechanism and system resource adequacy is where the bulk of our revenues are currently coming from.

And we'd like to see that move towards more localized and more flexible resource adequacy. I think the challenge is at this time we're not getting sufficient information from the utility buyers about the extent to which they're willing to place a premium on those products of our system array.

It costs us more to come forward with a local or a flexible resource. We need to insure that we're receiving sufficient value in return for those higher cost resources.

We'd also like to undertake more participation directly in the ISO spot markets. What perhaps sets OhmConnect apart from some other DR entities is that we actually want to be dispatched frequently. Our customers do best and they get the most satisfaction and benefit out of our service when they're frequently engaged, perhaps several times per week.

We would like to do more to participate in your real-time market. There are some challenges we need to overcome, though, in terms of how we can represent our commitment costs to your optimization, how we can come forward with the telemetry solution. And OhmConnect happens to be one of the entities that is working on such a solution through an EPIC program, no less.

We need to manage use limitations and run time restrictions. Again, we are a bit of an odd beast in that we are a combination of behavioral and automated response. We expect to see more and more automated, controllable, fully dispatchable response in the future. But the reality is the behavioral component is a non-negligible component.

There’s a lot of power in thousands and thousands of people taking simple actions like turning off light switches, and unplugging laptops, and so forth. We don’t want to dismiss that. But it does complicate the way we model our resources and how we participate in the market.

Finally, we do see an opportunity in the future, as well, through some of the non-wire alternative options. For instance, in the integrated distributed energy resources solicitations we expect to see later this year or earlier next year.

But to Susan’s point, we need to find a way to be able to stack those values and insure we’re able to receive the full value for the services that we’re providing, that our customers are providing.

COMMISSIONER MCALLISTER: We need to speed it up a little bit and get done.

MS. KENNEDY: I would say for those resources that can put in the metering and telemetry to provide a measured resource that has attributes that are no different than a generating resource, get rid of the energy baseline. It will destroy the economics of the market and there's no value proposition you can give to a host customer that makes up for that loss.

And then, the second piece of it is you've got to allow any integrated system, with demand response, and energy efficiency and, you know, load control technology like battery storage to access the funding for energy efficiency demand response and permanent load shifting.

MR. PANZER: First off, I love having the first and last word on this panel. I wish that always happened in life.

(Laughter)

MR. PANZER: So, traditionally, you know, we make money traditionally as an energy-efficiency program implementer. So, we're used to getting heavy energy-efficiency program administrative budgets.

As we move towards this model, we're actually focusing on only making a little bit of money off of the program admin, and really making money off of actually implementing projects and making money off of those projects.

Now, that turns our equation into really focusing on getting incentives into the project, which energy-efficiency incentives heavily drive the project more so than DR incentives do. And then, also, getting the energy efficiency to drive the cost savings on the project, as well.

As we look at it moving forward, you know, I mean as we look at the world of meter-based savings and, you know, basing this around AB 802 that’s huge. Because now we can actually look at saying, okay, utility, don’t take the risk on the performance of these projects and, you know, pay out incentives based on estimated savings, but pay an actual savings.

So, now that we’ve actually taken some risk out of it, we can actually talk to them about, you know, let’s pay based on the savings that are actually achieved.

And all of this starts leading us more in the direction of, you know, what the other panelists are talking about around really more of a transactive model. Over time, you know, we want to basically move away from just getting paid for energy efficiency, you know, because we’re running for programs or delivering for programs. But really about, you know, what sort of operational value are we driving back to the grid, you know? And how does that add up and how much value can we really get out of that, as opposed to them having to do some other sort of investment?

COMMISSIONER MCALLISTER: Thanks a lot. Great panel. Thanks everybody.

CHAIR WEISENMILLER: Yeah, thanks.

MS. RAITT: Thanks. So we’ll move on to our next panel, our EPIC DR Research and Development.

(Pause)

MS. RAITT: So if our panelists could go ahead and come up to their places at the front tables, that would be great.

(Pause)

MR. HUNGERFORD: Good afternoon, Commissioners. Thank you for staying for this panel. I think we’re to -- this is a nice segue to this panel, because the last thing we were talking about was the need for some sort of transactive mechanism for buying and selling energy. And this panel is going to talk about some EPIC research, an investment that the Energy Commission has made using EPIC funds, and trying to understand better how such a signal might work, and to test that idea with a number of different customer groups, using different approaches to providing demand response to the system.

Would you advance? Yeah, there we go.

The overview of this solicitation is the name is Advancing Solutions, that allow customers to manage their energy demand through the use of transactive signals. The basic idea was to compare these different customer groups and their potential for responding, and to try to achieve the goal of expanding participation by engaging large numbers of small loads in demand response, and trying to figure out a way to create a value proposition for that participation, which is exactly what we've been talking about all day.

We had a number of specific goals in mind. We wanted to test some of the technical aspects of communications and response. We wanted to test capabilities on both the supply side and the demand side approaches for load-following approaches. We wanted to develop strategies for overcoming technical, institutional and regulatory barriers to expanding ER participation. And we wanted to test and assess how groups or aggregations of distributed resources could respond to current, planned and potential price signals.

There were three groups that we allocated funds to, three different sort of focuses of research. We had one area that was to develop a transactive signal, to try to find the -- what the grid would value, what the system needs were and try to translate that into some sort of mechanism to provide a proxy signal or a proxy price signal to customers, so that they could see -- we could see what would happen in such a scenario, if customers were allowed to respond to such a signal.

And our first presenter will be Electric Power Research Institute, because they won that contract.

Move on to the next slide please.

The other category, one other category, one of the other two categories was demand response as a supply-side resource. And we had three -- we have three recipients who are currently doing projects where they are trying to provide resources that can bid into ISO markets, BMW, Center for Sustainable Energy, and OhmConnect. And we have two of them of here today on the panel, BMW and OhmConnect.

If you could go to the next slide please?

The second category was to look at the load modifying side, DR as a demand-side research. And EPRI has a project. You can read the different projects. But what -- they're all a little bit different in that they look at different customer groups and different approaches to provide demand response. And we're excited to see that they're looking at residential customers, commercial customers, specific narrow areas of commercial customers that have high potential for demand response. And we're looking forward to seeing the results of these projects.

We have one representative today, Universal Devices, Inc., that will be telling us about their particular project.

So if we can move on to the next slide.

We have a couple of questions that we're going to be asking these folks. But first, I'm going to have them introduce themselves, and then give a brief cover -- brief coverage of their project. I'm going to give a little more time to the transactive signal project at EPRI to sort of explain sort of the context for what they're doing. And then we'll have the other three panelists talk about how their -- talk about their specific projects and approaches.

And so Girish Ghatikar and Walk Johnson are here from EPRI to tell us a little bit about their project.

Please, go ahead.

MR. GHATIKAR: Oh, there you go. Sorry. It's good to be here again, now talking about the new advances in the demand response for the State of

California.

As we know, the State of California has always been a leader in advancing technologies for energy, specifically in electricity. And this is an area that has a lot of potential. And we are looking into how we can scale demand response, or rather advanced demand response in the changing grid system, especially the high-penetration renewables and decolonization in mind.

The discussions I will be representing is EPRI, but this is a very new topic, so there are a lot of new discussions. So I might get a little, you know, passionate about things, but I'll try to keep it as, you know, high level as possible to make sure that the concepts are very well understood.

So I'm going to talk about a little bit of the project goals and objectives, analysis, what we have done for the signal design, the preliminary findings, and then open the discussions.

Again, this project is also is representing EPRI Group 3 project on the transactive signals, and not so much on the, you know, Group 2 project that David mentioned, as well.

And also, the focus of the project is in the three specific categories, and they all are having an under-arching theme and goal, that is how to design and implement operational deployed transactive load management. That's a term CEC has used in the, you know, funding of a portion of the solicitation. And sometimes that becomes a red herring among many other stakeholders in the grid, especially when you look at the utilities and ISOs. We tried to define that a little bit more in the context of when we were working on this project, working with the rest of the eight different Group 1 and Group 2 Teams. But the idea there is to facilitate demand response in California by utility customers and others, and others in the sense, like, you know, the service providers, et cetera.

So the project has three major elements. The design part of the signal; what does a transactive load management signal really should comprise of, considering the markets that we have here? Implement a kind of a reference model, not necessarily a fully scaled model of that, and then operate that. And the implementation operation is along in close coordination with the other eight projects, so we set a common baseline of performances and evaluate the performances of the customers, as well as the different loads, against those from a non-objective and a neutral perspective.

So if you look at the overall in architecture or the fundamental, you know, idea, how we came up with this, there’s a lot of thought that’s gone behind it. So I would like to focus on the left side of the screen, which is what we call a transactive load management price (indiscernible). A lot of people in the earlier panels discussed about panels to devices, you know, providing customers with real-time pricing, et cetera, removing baseline, and things like those. But it’s easier said than done; right?

California has a very regulated market. We have very structured wholesale market prices for real time, as well as day-ahead market prices, but those are not reflected in the retail customers, particular the IOU customer, the majority of the IOU customers.

So, first of all, we had to really fundamentally understand how the California electricity system works and the market system work, and come up with a design that allows us to really start thinking about how do we determine the price? And that was the term where we coined TML price (indiscernible) point that consider two major elements; one is demand-side layer, and second is supplied-side layer. So both of these becomes a data input for us to really understand model, you know, based on their needs, as well as in real-time needs, the prices at a specific point. These points could be dependent on the analysis and the market rules and decisions that could be further, later.

And then the output of this is the information of price-output layer, which is the real-time prices. It could be day-ahead hourly prices. It could be a day-off hourly prices. It's 15-minute prices. It all depends on how we want to structure the market in the future. And those signals would be communicated as a transactive load management signal to the eight project -- to the customers through those eight projects.

So that's where our role really ends is to really -- the left side is where we're focusing on. And the interface, we call it a price services interface, and it's modeled against the NIST, the National Initiatives -- energy -- Services Interface model, as well. And what we are planning to use is using the open OpenADR, existing, you know, standard that is used by California and those 12 utilities for commercial-industrial demand response, Automated Demand Response Program.

But the idea behind this whole (indiscernible) of the signal is to be standard agnostic. Standard is a good approach but, you know, we want to develop a signal that's completely agnostic of the standard.

So if you look at the analysis that has gone into looking at the different projects, we queried and we have a Technical Advisory Group among all these project members and many of their folks. And also the, you know, generic teamwork and the experiences we have, you know, before I moved to EPRI, I was (indiscernible) Lawrence Berkeley National Lab. So, you know, I was responsible for understanding, over a decade, understanding demand response, (indiscernible), OpenADR, signals, et cetera. It’s how are those translated so that we don’t lose that rich body of science, rich body of knowledge?

And based on that, we came up with four key aspects that need to be considered as part of the transactive load management signal. One is, of course, the price in generation source. How do you determine the price that exists in the grid right now, if there is one? And then we’ve started at the location marginal prices that California ISO has.

The second one is a locational targeting. A lot of other people spoke about a locational target for DR, if they really have a need for a DR in a specific area, or there’s an excess generation in a specific area, how do we understand that locational is targeted for either over-generation or under-generation conditions?

The third area is a social and generational area, source of generation and social cost. One is a lot of people talk about the prices, but there is a movement in certain projects. I think BMW and UCLA are looking at the social cost. Are customers willing to change their energy use based on the source of generation? If you're -- you have a high wind blowing, are you willing to charge your electric car at night, as opposed to charging them in the afternoon, or maybe in the evening when there's excess -- you know, a fossil-based generation? So all these are also becoming an important factor in consideration.

And finally, notification (indiscernible) intervals, and this is not anything new. We have seen that in the history, that when do you notify and how long the DR response needs to be is a key determinant of whether our customers can participate, and what type of loads can participate in demand response programs.

So when we bring all of this together, again, there's a lot of body of work that's happening. Because of the regulated structure of the California market, we do have wholesale market prices. You know, the locational marginal prices are a good representation of that. And then we have, you know, the whole retail prices. What's missing is the layer in between, the distribution. What happens in how do the distribution utilities, which are very important, integral stakeholder in this, need to be considered?

What we came up with, a distribution system adjustment that takes into many different accounts, not necessarily just the existing energy condition losses in the LMP prices, but also supply-side variability and demand-side variability. Demand is getting more variable with rooftop PV and storage and electric vehicle installed. How do you account for this variability in the pricing structures? And then come up with what we call market-based transaction load management price signal. That is incorporating all the stakeholders in the grid, but also real system and market conditions that can be, you know, published. And each of these technologies and vendors and customers can determine how best they can provide the resource to, you know, meet the grid needs, as well as their individual, you know, energy consumption needs.

So if you look at the whole idea about compressing this into a generic signal, at the end of the day it comes down to when -- how quickly do you notify, right, that the price exists? And how much time people will really have to when the price becomes active? And then, how long the price is active. All of that will be a key determinant in what kind of load, how much load, what kind of end users can participate? An example is if you give day-ahead, you know, prices, somebody can execute a pre-queling (phonetic) strategy, right, because there's sufficient time. But if you only notify in an hour that this is a price for next hour, maybe you would not be able to do that. So electric vehicle or a battery storage or a lighting load might be more receptive to those kind of response.

So we then created the generic signals that could be translated across different notification period times, the start time and the end time, across different intervals. It could go to any one minute or sub-one minute if the market is willing to do that, customers and technology are willing to do that. We are not saying there has to be one. The results will tell us what the results -- you know, what a good signal would be. But at least we are creating a generic signal for that.

And as I said, you know, we're using the existing OPA (phonetic) standard, called OpenADR, you know, to, you know, send these signals to all these projects in a way that allows them to receive the signal in a standardized form so
next -- in future, if new technologies and innovations are fostered, they have a way to really subscribe to

these prices and have the customers easily respond with value propositions that's determined by the market. That takes away the whole needs of the baseline, it takes out the whole need of the telemetry, and most of the challenges that we have discussed this morning.

But again, I want to emphasize the fact that OpenADR is used as a reference model. Any standard, you know, could be used, as long as it's supposed (phonetic) to signaling infrastructure. But standard is a very important component to enable scaling and the cost effectiveness and innovation.

So if you look at the preliminary findings, and this is my last slide, we narrowed down from this project perspective, it's a very small project, it's not a large project, small relative to other projects, as well, we decided that a 24-hour day-ahead LMPs constitute the temporal basis for the TLM signal, because it's all about -- based on time and location, are critical components. We want to use the, you know, LMP prices. And the P-notes (phonetic), which CalISO already has, has the lowest spatial disaggregation point for us to really start thinking about this.

The third one is the distribution system, where we're able to get adjustment, is a very important part of this. This is where the utilities and the ISO needs to be very actively involved moving forward. You know, we have some, to some extent -- you know, EPRI has a lot of utility members. We do have a little bit. But we want more extensive participation.

And finally, the integrated inclusive approach. In line with the EPRI work on the integrated grid, integrated energy network, is how do we make sure integrated inclusive approach of both the ISO and the electric utilities, you know, could be leveraged for a fair market TML prices, where the consumers benefit, as well as the technology vendors and the innovation that's happening here in California also benefit?

So that's -- that was my last slide. Thank you again.

MR. HUNGERFORD: Thank you, Girish.

I think we should just move on and have our other panelists introduce themselves.

The first panelist on our list, and this is for no other reason than the list is constructed this way, we'll have Matt Duesterberg from OhmConnect tell us a little bit about their project. You have heard from his coworker, John Anderson. And Matt's going to be talking about some of the things the John didn't talk about.

MR. DUESTERBERG: Thanks, David.

And thank you, Commissioners, and Mr. Casey, for the opportunity.

I wanted to give a little background on OhmConnect. You've already heard a little bit from John, but I'll give you -- I'm the CEO/Cofounder, and I'm going to give you a little bit of an origin story.

I both traded on the electricity markets and California ISO when the opened up in 2008 and 2009, well, 2009 because it was delayed for a year. And then I was also in a utility data -- meter data analytics company. So I've seen both sides of the spectrum. And the purpose of OhmConnect is really to drive customer engagement. And there's a tremendous amount of useful smart-meter data in 60 to 80 percent of the population in the U.S. that is being underutilized right now.

So as part of the project, and I want to loop back to some of the conversation we had from this last panel because I think that last set of questions were actually really interesting, I'll speak briefly to the project, and then we'll loop back.

So if you can forward to the slide? Oh, I do.

So we're working with the UC Berkeley and EPRI on this project. It's a fairly simple project. We are attacking three things; user acquisition, user engagement and telemetry for real-time market participation. I can provide you more information, if you want, after, but I want to just go through the high level.

First of all, from a user acquisition perspective, this has been tremendously successful. We've had over 16,000 users sign up; 8,000 people with their utility credentials at half the budget that we originally allocated for this project. We've dispatched over 250,000 Ohm R (phonetic) events for our users, and have consistent reductions and very high automation uptake. We're still working -- and those events were outside of the EPRI dispatch signal. That was our own internal testing processes. And we're looking to incorporate the EPRI dispatch signal. We're also working closely with CAISO and EPRI on building a low-cost pathway for telemetry.

We have a strong user base, I mentioned that, large data set, in initial days. This is the graph of users growing over time. You can see some big spikes in October, also in March and in June, mainly through referrals. So this is a very viral platform. People refer their friends. They talk about it at cocktail parties and they get their friends to sign up.

We have high benefits to California. We're in a lot of low-income communities. And this is just within the grant. Our actual business has about 10X those users, 10X to 20X. And we have, as John mentioned, dozens of resources on the CAISO and dozens of megawatts being bid in on a daily basis.

Now I want to take this extra time, and I blew through that, and happy to answer any questions about that, but I want to go back to some of these questions that were talked about at the end of the last panel.

And, Chair Weisenmiller, you had asked, what does this market-based approach look like?

Keith, you mentioned, what is your bread and butter?

And, Commissioner McAllister, you kind of said, what can we throw at it?

And I think this is all fundamentally stemming from what I see as a paradigm shift. And what we've traditionally done in the regulated energy space is future resources. And I think that was good traditionally. I think going forward we have to change. And when I say -- and we have to now purchase products. And let me just impact that for you a little bit.

When I think of resources, I think of a gas power plant, so whether it's combined-cycle or single-turbine or solar or storage or demand response, those are resources. But when I think of products, I think of what the grid actually needs, and this is what the CAISO is procuring, the day-ahead energy, the real-time energy, the resource adequacy.

And we started to get into that discussion, and Susan put it best, which is we have all these silos for our resources, because we think these resources can have -- can affect these products. Demand response can affect resource adequacy, but demand response cannot affect, say real-time energy. And when we try and break those silos, we start to see all sorts of integration issues. And I think that the framework we should start thinking about is if we can move to a product-based procurement process.

So I don't want to be in a beauty contest where, you know, somebody who's talked to a utility, has better salespeople than my salespeople. I want to have a proposal, next to a competitor, where I could give this to five different people and all five of those people will come back with the exact same procurement. It's not a qualitative procurement, it is a quantitative procurement with penalties, with real financial penalties, with real financial risk.

And that's when you start to see true innovation happen. That's when you -- there's -- I mean, we're really close to Silicon Valley, and there's tons of interest in trying to innovate in this sector. But when we're in siloed little pockets, we're unable to access some of the bigger pies. And if we're successful, we're limited on our side.

And I just wanted to throw that out there as kind of my statements, opening.

CHAIR WEISENMILLER: We'd just note that we are going to ask everyone at the end of the day for comments in a couple of weeks. So certainly, anything, you know, that you want to hit more broadly, we'd love to get them in the comments, too. You don't have to squeeze them in right now, okay?

Go ahead.

MR. HUNGERFORD: Next is Michel Kohanim of Universal Devices.

Michel?

MR. KOHANIM: Hi. First of all, thank you for the award. And I'd like to thank David. He's been extremely important in our quest. And I'd like thank CAISO, as well as SCE, because they supported us throughout the project.

I'm not going to talk about the company. I'm just going to talk about what we -- why this project is very, very important, and it's for two reasons.

Number one is David, I don't know whether or not intentionally or not, moved the question of DR to residential and SMB, which is very important. As Dr. Faruqui said, you can have probably 10 to 14 percent load.

The other important thing is that the project itself provides a blueprint. And the most important components that I think is necessary for something that I call unified systems of energy, or USE, without which we're just going to keep going through these conversations for -- in perpetuity, talking about telemetry baselines, measurement, verification, and we're not going to get anywhere, or we're going to get somewhere, but not where we want to be.

So those four very important components are IOT, smart-grid technologies. These are -- I took them, literally, out of the project requirements. And without IOT and grid -- smart-grid technologies, there is no way we can minimize the costs and complexity of customer participation, there is literally no way.

Number two is using or integrating renewable resources. Of course, there is no question about that.

Number three is the usage of transactive signals. And, of course, we can argue about what transactive signal or transactive energy is, but in our view it has to include the possibility of getting rid of measurement verification and baselines. Transactions are complete. You don't need baselines. You don't measurement and verification.

And number four is at the top, behind-the-meter load management system. And to me that basically means that you need an energy management system. You need a brain within the premise that understands what needs to be done based on transactive signals. And these transactive signals, I know we keep talking about prices to devices, but it can't be just be prices to devices. Because what if all devices just turn on at the same time, or turn off at the same time? What happens to recouping the investment of utilities, transportation, distribution?

So for us, these four different components are the basic components.

And thank you, David, for including them in the project.

And this is our implementation. And it's a masterpiece because it includes ten different and disparate systems getting information from smart meters, real-time information from smart meters from geofencing, whether or not you're close to your home, from CAISO, five-minute interval data, and hopefully we can get to four-seconds by notification, and interestingly enough, Amazon Echo and Google Home, so that the customers can communicate with their devices. And everything is pretty much off the shelf. These are not proprietary devices. You can buy the thermostats and pool pumps from Amazon, and that was part of our sub-mission and integration with DR.

And with that, I'll give it back to David. Thank you.

MR. HUNGERFORD: Thank you, Michel.

Let's see, I guess Adam Langton from BMW is here. He's going to tell you a little bit about his project.

MR. LANGTON: Thank you, David.

Thank you to CEC, CPUC and CAISO for the opportunity to be here and explain about our project, our EPIC project.

The project is called Total Charge Management, or TCM. And it is a project where we're testing advanced forms of load control for electric vehicles so that electric vehicles can serve as a grid resource for the utility and/or the wholesale market. And I'm going to give a little background on the project, and then jump into some of kind of the lessons learned, since I think that's where the focus is right now.

What's unique about the BMW approach to smart charging is that we rely on the vehicle telematic system as our communication method with the vehicle. So we are able to send messages to our vehicles using the telematic system to start or stop or schedule charging. And so if we are able to work with the utility or the wholesale market to get messages regarding what we need to do, those messages can go to our software back ends, and then we can send those messages back to the participating vehicles. And by doing that, we're able to serve -- these vehicles are able to serve as a demand response resource or other types of resources on the wholesale market.

Electric vehicles are a really attractive grid resource and demand resource because they're a very large appliance, relative to most of the other appliances in a household. Our vehicles are usually charged at a rate of about 6 kilowatts, and they need to do that for several hours every day to meet the driver's driving needs.

And also, a vehicle has a lot of flexibility in terms of its charging. The average vehicle spends about 22, maybe even 23 hours per day parked. And so during that time, if a vehicle is plugged in it could be providing smart charging. It's an opportunity to do smart charging.

Vehicles also present some challenges. Vehicles are critical for somebody's mobility need, so they're relying on that to get from place to place. And they also, obviously, move. So they move from one point on the grid to another point on the grid. So those present challenges to maximizing the value of the resource.

And that's what -- those are all aspects that we want to explore in this pilot.

We are -- we've enrolled nearly 400 electric vehicle drivers in the Bay Area who are participating in this project. They are drivers of BMW i3 or i8 vehicles. They're also drivers of our plugin hybrid vehicles, as well. So we're getting to test both all electric vehicles and the plugin hybrid vehicles.

And I mentioned, we're using a telematics approach. So we get messages from the grid. We rely on getting those messages through the OpenADR standard. Those messages go to our backend, our software backend. And then we send those messages down to the individual vehicles that are participating. We give our participants a smart phone app so that they can opt out of events whenever they want to. Our approach to demand response has been that drivers who are participating in this program are included in every event, so that we don't have to ask them if they want to participate or not. And instead, we give them the opportunity to opt out whenever they want, opt out for individual events, or on a daily basis. They can opt out for the entire day, if they need to.

We also look at the vehicle to see where it's plugged in, what the state of charge is. And if we determine that it's appropriate to include them in demand response, we can go ahead and do that. And that way, we're always trying to prioritize the customer's mobility. That's obviously why they purchase the vehicle.

So in this particular project, we've done testing for basic demand response where we've curtailed the load from the vehicles, so we have some, a little bit, of experience with that.

What we're doing now in this pilot project is we want to test the ability to optimize the nighttime charging. We can optimize against the price signal, the transactive energy signal that EPRI will provide. We can also optimize against renewable energy. We also want to test excluding certain hours of charging so that we can provide grid benefits to the utility that way.

We also want to see if we can align charging with solar energy. As you guys are well aware, there's a lot more solar energy coming on the grid in the afternoons. And in the near future, we'll start to need more load in the afternoons. And we want to test the ability to shift electric vehicle charging to those hours in the afternoon, when there's a lot of solar.

Because we are relying on the telematic system, we can actually manage the vehicle charging wherever the vehicle is. As long as it's plugged in, we can communicate to the vehicle and we can send it messages about whether to charge or not.

So while the fact that a vehicle moved is often viewed as a disadvantage when it comes to a demand response resource, we actually think it can be an advantage in many ways. We have a resource that can actually show up on different parts of the grid and can provide benefits at a different -- at one place on the grid and on another place of the grid different times of the day. So we think that can be really valuable in the long term when we have a lot of electric vehicles and the utilities are trying to deal with a lot of solar energy in the afternoon. That certainly presents a lot of challenges with engaging the customers and getting them to plug in, having the opportunities to do that, so that's what this pilot project is all about.

So my last slide that I'd like to talk about is kind of the lessons learned so far, and I want to focus on kind of the enrollment process and our experiences there.

You know, one of the challenges that we've encountered, all of these, all of our customers, are households. They're all customers who drive electric vehicles. They are not familiar with demand response. They don't have a lot of experience with the energy markets or their, you know, utility procurement or any of that. The scissor form (phonetic) is certainly a challenge that we've encountered. It's complex. We lose customers when we send them the scissor form because they're confused about what it is. They need to provide the SID number, which has been a challenge. I think other folks have probably talked about that already. So that's one challenge that we encounter a lot with the customers.

We have to spend a lot of time energy engaging the customers on what this project is, what smart charging is, what demand response is. And we have to get them to sign forms. And it's only after we sign the form that we can figure out whether or not they have a conflict. Some customers are in other programs that are a conflict and prevent them from participating in this. And we don't find that out until after we've had them sign several forms and engage with them a lot.

It would be helpful if there was a way that we could identify that very quickly, perhaps some coding on the bill or some indication on the bill so that the customer would know that they were in a program and that they could share that with us. That way, we could identify right away customers that will be easy to enroll and customers that will be more difficult. So that's a challenge that we've encountered along the way.

For customers that are in other programs, some programs, like other demand response programs or certain tier (phonetic) programs, prevent a customer from participating in our program. And our program is really geared toward the electric vehicle, whereas other programs, like Smart AC, are really geared toward the air conditioning unit.

So when it comes to thinking about at the appliance level, we don't really have a solution that makes it easy for households to engage in that or -- and there's not really any way to participate in two programs at the same time. So that's something we should -- I think we should explore how to do that and ways to make that much easier for customers to participate.

Another challenge we've run into is that the Rule 24 rules are complex for and not clear in terms of un-enrolling customers. So we've encountered a number of customers who are already in existing demand response programs, but we're interested in switching to our program. And when we talked to them, they would be interested in the program and they would agree to switch, but they often had trouble with other third-party providers in terms of getting them to switch. The rules weren't clear in terms of what the other third party needs to do and how we can engage with them.

So I would ask the agencies to help us figure out ways to make it easier to un-enroll customers when they want to switch to new programs.

MR. HUNGERFORD: All right.

MR. LANGTON: And that's it for me.

MR. HUNGERFORD: Okay. Thank you, Adam.

You -- if we can go back to my questions from the main slide, you'll see that Adam has already answered question number two from his perspective.

And so I think we can move to the -- I think we can just go straight to the other panelists talking about the barriers that they've run into, the problems that they've run into in running their programs.

And I think I'd like to start with Michel, and then we'll go Matt on that.

MR. KOHANIM: Well, of course, the scissor (phonetic) process is a little bit challenging.

The other issue is the lack of standards specifically communicating with inverters. And so we had to make our own bridge that communicates with any type of invertor.

Those are basically our own challenges.

The rest, for a couple of customers, they didn't have smart meters, but thanks to SCE, they immediately went and installed the smart meters, so not much.

MR. HUNGERFORD: And just to follow up, look at the first question. What kind of --

MR. KOHANIM: We --

MR. HUNGERFORD: -- product are you going to be able -- would your customers be able to provide?

MR. KOHANIM: Well, all of them. Shape, shift, shed, shimmy.

MR. HUNGERFORD: Okay.

MR. KOHANIM: Thank you.

MR. HUNGERFORD: I wanted to drive that home.

MR. KOHANIM: All of them, definitely.

MR. HUNGERFORD: All right. Matt?

MR. DUESTERBERG: Great. I'll divest to the first one.

The shape, shift, shed, shimmy, John mentioned this. But we are currently participating in the day-ahead energy market about once or twice a week. So we are already in kind of the process of doing shift. We would love to do shimmy, that's part of the telemetry solution: Can we get real-time data to the CAISO on a five-minute basis from residential homes without putting in a new meter? And we're obviously doing shed, because we're contracted in for dozens of megawatts.

We see that going forward, and this is back to that kind of question of products versus resources where these types of energy products are extremely valuable, but they're not priced currently, and I'm talking about flex RA, local RA, flex ramping. And we want to make sure that those products are available to not only demand response, but any type of resource that can provide that. And it frightens me a little bit that we have a dedicated workshop to demand response and a dedicated workshop to storage and a dedicated workshop to energy efficiency when really these types of services are being all provided by similar resources. And to be siloed from that, that's problematic.

In terms of barriers that we've had running our project, specifically the main challenge has been data. As you guys might imagine, multiple tens of thousands of customers, we start to run into data issues on the edge cases. And if only one percent of users have a broken meter, for example, that's still hundreds or thousands of users, and we're seeing that. We're seeing users where a meter goes from 0.1 kilowatt to 25 kilowatt and back to 0.1 kilowatt. And those are meters that are being bid into the California ISO market. Those are validated from the utilities.

So John enumerated a bunch of these also, CCAs with historical data, we're not getting that. Users will randomly miss data. The utility will just not send it to us. And, for example, if you go to back to the scissor process, just registering users has been quite difficult at scale.

So, for example, SDG&E has a service where you can page through tens of customers with each page and it's all manual, you can't do an API to this. We have 7,000 customers, and so that's 700 pages of links that we'd have to click to, and there's no order to that.

So if somebody -- and we're getting this all the time, an SDG&E user will ping me and say, "Hey, what's happening with my data," and I'd be like, "Well, we can spend about five to six hours trying to figure out which page you're on, or we can ping SDG&E's Help Service, and their Help Service is about two to three months delay. So our users are just having a poor experience from that.

We have been working closely with the utilities on that front, getting data from utilities to third parties. And we are breaking down barriers, and that's been useful.

There is one other, I would say, self-inflicted barrier that we've had. And I think it's important for us all to recognize this. It's actually been because we've constrained ourselves in the grant process. And our users in the grant program is actually having a much worse experience than our users that have had our product change every month since the grant started 12 months ago.

I don't know if you guys are familiar with NPS, net promoter score. This is one of the most widely used metrics for consumer engagement. And all of you guys have seen this question, it's: How like would you refer this product to a friend, one to ten? If you hit one to six, you're a net detractor, seven and eight are neutral, nine and ten are promoters. And so you can have a net promoter score anywhere from negative 100 to 100. Most utilities are around 10, 15. Facebook, in its heyday, was around 50. Our products that is not in the grant is not in the grant is around 50. Our product that is in the grant is about ten, and that's because our product is stale.

And this highlights the fact that if you work within these very static boundaries, and, you know, I liken this a lot to my history with utility (indiscernible). And when I was selling to FPL and WE Energies (phonetic) and PG&E and Pico, they wanted it this way. And when we implemented it this way, you get terrible engagement. When you have a more dynamic thing that changes every week, every month, we've pushing code every day, you get a very high engagement rate.

MR. HUNGERFORD: Thank you.

MR. HUNGERFORD: All right. Does anyone have any additional comments, Rish and Walt?

MR. JOHNSON: Yeah. My name is Walt Johnson. I'm with EPRI, as well. And I wear two hats in this.

As was mentioned, I think, EPRI has two aspects of engagement with this project. On the one hand, we are subcontracting with Matt, with OhmConnect, looking at the telemetry requirements and the technical barriers to participation. And I've been leading that effort in terms of looking at what the other ISOs and RTOs in North America are doing in that regard.

And I just wanted to note that we've heard several folks up here today and various panels comment on the challenges that the telemetry requirements, the generator-like telemetry requirements that exist for a number of the products at the ISO, but at the same time we also heard Jill from the ISO express the belief that more telemetry was going to be required in the future. I think that's a challenge, let's put it that way. And we have, certainly, discovered in some of our work, which was reported, that there are other ISOs, PJM is an example, where they are much less interested in receiving telemetry for a significant portion of their -- of products, of the DR products.

Just a curious observation. There seem to be different philosophies at work with respect to the need for telemetry. And I think that will be an interesting outcome from some of that work. It's a barrier here, whether we make headway on that through this project or other follow-ons, I think would be interesting.

The other I want to comment on is Rish gave our presentation, but I'm also the, technically, the Project Manager on the Transactive Signal Project. And in that regard, one thing that we've learned as far as a challenge, I would say, is with respect to the bifurcation that's occurred. The supply-side resources that go into the ISO markets have a lot of, essentially, transactive character already there. It's a market-based solution. It generates a price, which is locational relevant in the LMPs, and that seems to be the granularity that our recipients of the signal are interested in. At the same time, it has exposed, I think, the complexity of those projects which are trying to deal with the demand-side resources, because although we have a simple price that we can trace, if you will, on the supply side, back to the ISO clearing prices, there's nothing like that on the demand side. By the time the settlement of the demand that's occurring or the lack level rather than the LMP level is being hidden, if you will behind various retail tariffs, it means that trying to provide a meaningful signal that the projects that are trying to consume the demand side and respond to a demand-side transactive signal, it's a much more complicated sort of thing to try to figure out what that signal maybe should look like and have it really be effective for the recipient project.

So I think that that's just an observation, that greater traceability perhaps or -- okay.

CHAIR WEISENMILLER: Yeah. No. I was going to say, I think we've got to wrap up now. But, I mean, it is clear that one of the issues that had not really come up before you raised it was just we have retail rates on the one hand that would certainly affect the load side of stuff, and we have a wholesale market on the other hand. And the price signals in both are different, they're not linked. It's sort of hard enough to get, say, retail rates straight or to get ISO prices straight, much less getting the two of them coherent.

MR. JOHNSON: Exactly.

CHAIR WEISENMILLER: But --

MR. JOHNSON: And in the design of HVAC --

CHAIR WEISENMILLER: But we're going to have to move on.

MR. JOHNSON: That's fine.

CHAIR WEISENMILLER: So thank you.

MR. JOHNSON: So that's the challenge we have.

CHAIR WEISENMILLER: Yeah.

MR. JOHNSON: We're looking at probably designing two signals, and don't know how to design one of them, frankly.

CHAIR WEISENMILLER: Well, yeah. No. But, I mean, again, that's a border policy issue. I have no illusions that's going to be resolved anywhere quickly. I'm assuming most of the participants so far have been saying they've been looking more at the wholesale markets as potentially having more value than the retail markets.

But again, at this point, I certainly encourage, if any of my Commissioners have comments. But as I said, we -- you know, it's a long day. We have one more talk. We have public comment.

So I thank you all of you, but we've got to move on.

Andrew?

COMMISSIONER MCALLISTER: No.

MS. RAITT: Great. Thanks. So our last speaker is Gabe Taylor from the Energy Commission.

MR. TAYLOR: Good afternoon, Commissioners and everybody.

When they asked me to present the Building Standards Proposal for Demand Response at the workshop, I was very excited. And then they -- and then I got the agenda and I saw I was the last presentation of the day. I'm anchoring this particular marathon. So I immediately deleted half my slides. So what you see here is a result of that. It is a very brief summary. If you need more information, please let me know. I've already talked to Jill and Adriana with the ISO, so I'm going to talk to the ISO a little more closely about this, but just let me know if you need more information. My contact information is at the end.

So my name is Gabriel Taylor. I am an Engineer in the Building Standards Development Office. And what follows here is a brief summary of the 2019 proposal for modifying the Building Standards, Title 24, Part 6 Building Standards for demand response.

In 1976 the Warren-Alquist Act not just directed but authorized the Energy Commission to implement regulations for electrical load management and demand response, and explicitly included both storage and automation.

Let’s see here.

The proposal for 2019 is our continued movement towards zero-net energy in the built environment in California. These standards will bring us firmly towards our goal and reach standards at the local level will bring many buildings built after 2020 to true zero-net energy production -- zero-net energy.

The 2019 proposal includes a requirement for distributed residential PV. And I know this is a touchy topic. I’m looking forward to discussing that with people. The standards consider, however, demand flexibility. As you know, these building standards are considered the value of the energy, the value of the savings of the energy and the energy that’s consumed in the built environment. So when we mandate solar, we also consider the value of that solar as it’s generated.

And in order to get to that true zero-net energy goal, you have to take into account the harmonization of not just the distributed generation, but also the residential integration technologies that exist, such as demand response, to harmonize that energy with the grid, and to minimize and maximize the benefit, both to the consumer and to the grid to lower overall costs.

So the proposed changes break up into two sections. We have a whole bunch of cleanup sections, and then we also have some code change sections. The code change is a little smaller. I'm going to briefly go through the cleanup sections, and then focus on the code change.

Over the years, so since 1976, the Energy Commission has added numerous sections of demand response language to the Building Code. It's been peppered throughout the code. Usually it's relatively consistent but not always. So in this cycle we're going to collect all that language together, we're going to put it into one section, and we're going to make sure it's all consistent. We're also going to make sure it's consistent with ASHRAE 90.1. That includes changing a few definitions and eliminating some language in the code that has proven to be confusing to implementers.

The second section is the actual change, and this is, I think, a very big deal. And this is the requirement that all external communications point to the OpenADR 2.0A or 2.0B protocol. This consolidates the communications and control specifications within the Building Standards so that all demand response and controls that are specified in various sections, lighting or HVAC or what have you, all use the same open-source communications protocol. This isn't entirely a new requirement. The OpenADR protocol is simply a language that tells a device how to talk to another device or how to get information from the utility or from a demand response program or aggregator. The current code requires an open-source protocol but doesn't specify a specific one. That has proven to be confusing. Many implementers have called us or called OpenADR or others saying what do we do, and they just want to know.

So this is, I think, a real policy and research success story. Many of you know this. And I know Mary Ann was firmly -- was very much involved with this. But OpenADR came from a California Energy Commission funded research starting in 2002, following the energy crisis. We funded the Lawrence Berkeley National Labs and the Demand Response Research Center. They ended up pulling in many of the utilities, standards-setting organizations, both inside and outside California, globally. And in 2003 through 2006, we had a number of pilots and field trials throughout California.

In 2009, OpenADR 1.0 was issued. That was an Energy Commission-published document, a state document. And then that moved to -- it was taken up by the nonprofit, OpenADR Alliance, in 2011. 2.0A was published in -- 2.0B in 2014.

So this is a success story where the Energy Commission saw a need and funded research to meet that need. And now we are able to propose a proven solution. This has been out in industry, well tested. It is familiar to most of the players, if not all of the players, in industry. And this is a proven solution that we are now proposing to include in the code.

The Title 24 update process is a three-year cycle. I like to think of it as a subway station. We’ve got the 2019 train pulling in. We’re loading it with all our ideas. It’s got to get out of the way so the 2022 train can come in.

Right now we’re in the pre-rulemaking section here in 2017. Later this year we will issue our draft Expressed Terms, our proposed updated language, and we’ll enter the formal rulemaking that will proceed through early 2018. If all goes as planned, the Energy Commission will adopt that language in May of 2018. And then the Building Standards Commission will approve that language in December 2018, and then it will be approximately a year between the final approval of that language and when it goes into effect.

Again, this has been a very brief overview. It's late in the day.

CHAIR WEISENMILLER: No. Thank you.

MR. TAYLOR: Please contact me if you have any questions.

CHAIR WEISENMILLER: Thank you. I mean, certainly, I can well imagine how the provisions, you know, sort of popped up over 30 or 40 years. And going back and getting them all consistent was a yeoman's service. And I think, also, upgrade to the OpenADR is important.

So again, obviously, important on all this. I'm sure it's, you know, as I said, going through each of the documents and trying to get them consistent and lined up is one of the fundamental things that's very important, so thanks.

MR. TAYLOR: You're very welcome.

COMMISSIONER MCALLISTER: Yeah. So as the lead on Building Standards, you know, I appreciate the level. There's a lot of detail in there that you did not present, so I really appreciate that overview.

And I just want to highlight, this is -- you know, it takes 20 years to get from Point A to Point B for real change, and that's kind of what's happened here. Now we're going to see a lot of fruits of all that work, so I want to thank everybody who was -- who participated in that over a long, long stretch of time.

And I'm not going to be able to stick around for public comments. So I just wanted to thank Martha and Keith, and certainly the Chair, for all of the leadership on the IEPR, generally, but you two specifically for being here.

And in addition to David Hungerford and Bryan Early, I wanted to thank you, Gabe, for all the work today. Both of you really did a lot of yeomen's labor to put this together. And I think it's going to pay off and move the conversation forward in a good way. So thanks for the presentation.

Do you guys have any questions? No? Okay.

CHAIR WEISENMILLER: Okay.

COMMISSIONER MCALLISTER: All right.

CHAIR WEISENMILLER: So let's go to public comment. Is there anyone in the room who has public comment?

Please come up, identify yourself. Again, I'll remind you that we're going to ask for written comments.

So if you have lengthy -- you've got three minutes. But if you -- you know, but certainly -- yeah, come on up, please. It's just, I'm telling you, we're really looking forward to written comments, too --

MR. KOHANIM: Okay.

CHAIR WEISENMILLER: -- along with --

MR. KOHANIM: Michel Kohanim. And my only question, or maybe confusion, is why is there such a problem with telemetry? Smart meters are around. Devices that read smart meters are around. OpenADR 2.0B allows smart meter information to be transported to CPUC -- to CAISO.

CHAIR WEISENMILLER: Again, you're getting --

MR. KOHANIM: So what is the problem?

CHAIR WEISENMILLER: You know, it's sort of the classic issue on the telemetry, you know, what sort of revenue, quality. And, you know, again, you're right. But, yeah, I mean, so again, I think it's -- you know, we were talking earlier with a large CI. Yeah, it's pretty easy to see that you can really get things right. And as you try to move out into the residential and, you know, because the AMI, god bless, we were first-generation AMI, but I'd hate to imagine, you know, if people were going into the PUC on what we really should be putting in, what that would be.

But, you know, as I said, certainly cyber, you know, basically encourage technical groups to work through this.

Anyone else? Anyone online?

MS. RAITT: Anyone on WebEx have their hand up? So I don't think so, so we'll go ahead and open up the phone lines.

So if anyone on the phone wanted to make a comment, this is your opportunity. And if you're on the phone and don't want to comment, please mute your line. We're just taking a moment to open up the lines for anyone on the phone.

(Background phone line noise.)

MS. RAITT: Okay. No one. All right.

CHAIR WEISENMILLER: Okay.

MS. RAITT: I think we're done.

CHAIR WEISENMILLER: So you want to remind people when the written comments are due?

MS. RAITT: Yeah. Written comments are due August 22nd.

CHAIR WEISENMILLER: And again, we encourage everyone to look through all -- you know, again, we're looking for competence in records. So we certainly encourage people to hit across the board on stuff, so thanks.

Anyone? Any further words?

MR. CASEY: No. I just wanted to thank you, Chairman. And I want to thank all the speakers and panelists. It was a very informative day. And it's clear we've got a lot of challenges ahead and, certainly for the ISO, a lot of things to work through. And we look forward to working with all of you to find solutions to all of these, so thank you all.

CHAIR WEISENMILLER: Yeah. Again, thanks everyone. Interesting day. And again, let's try to figure out how we get the ramp, you know, to a much more interesting number, again, realizing again, we're talking more cumulative. You know, this whole boundary of EE, DR, you know, storage, you know, all the various silos.

But again, you know, I neglected to mention that I have to thank Susan. I think she's the -- and I've sent out a number of requests to people in Aliso Canyon to do something, anything, down there on demand response. And I think Susan is the only one who's really been that active, you know?

So thanks again.

(The workshop adjourned at 5:00 p.m.)

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