DOCKETED	
Docket Number:	21-IEPR-04
Project Title:	Energy Reliability
TN #:	241524
Document Title:	Transcript - IEPR Commissioner Workshop on Supply-Side Demand Response - Session 1 Reliability and Resource Planning Market Oppo
Description:	Transcript - IEPR Commissioner Workshop on Supply-Side Demand Response - Session 1 Reliability and Resource Planning Market Opportunity, and issues
Filer:	Raquel Kravitz
Organization:	California Energy Commission
Submitter Role:	Energy Commission
Submission Date:	2/11/2022 9:17:01 AM
Docketed Date:	2/11/2022

STATE OF CALIFORNIA

CALIFORNIA ENERGY COMMISSION

In the matter of,	)	
	)	Docket No. 21-IEPR-04
2021 Integrated Energy Policy	)	
Report (2021 IEPR)	)	RE: Supply-Side Demand
_____	)	Response

IEPR COMMISSIONER WORKSHOP ON SUPPLY-SIDE DEMAND RESPONSE

REMOTE ACCESS ONLY

FRIDAY, DECEMBER 3, 2021

SESSION 1: Supply-Side Demand Response – Reliability and Resource Planning, Market Opportunity, and Issues - 10:00 A.M.

Reported By:
Elise Hicks

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P R O C E E D I N G S

DECEMBER 3, 2021 10:01 A.M.

MS. RAITT: All right, we'll go ahead and get started. Good morning everybody, welcome to today's 2021 IEPR Commissioner Workshop on Supply-Side Demand Response.

I'm Heather Raitt, the Program Manager for the Integrated Energy Policy Report, known as the IEPR for short.

The workshop is being held remotely, consistent with Assembly Bill 361, to improve and enhance public access to state agency meetings during the COVID-19 pandemic by allowing teleconferencing options. The public can participate consistent with the directions provided in the notice for this workshop.

Our IEPR workshops are recorded and the recording will be linked to the CEC website shortly following this meeting. And a written transcript will be available in about a month.

To follow along, the schedule and slide decks have been docketed and are posted on the CEC's website. You can just look for the 2021 IEPR page.

Attendees may participate in the workshop today in a variety of days. For those joining through the online Zoom platform, the Q&A feature is available for

you to submit questions. You may also upgrade a question submitted by someone else. And to do that, click the thumbs up icon. Questions with the most upgrades are moved to the top of the queue.

We will reserve a few minutes after each of the panels to take a few questions, but we may not have time to address all the questions submitted.

Alternatively, attendees may make comments during the public comment period at the end of the morning and at the end of the afternoon sessions. Please note that we will not be responding to questions during the public comment period.

Written comments are also welcome and instructions for doing so are in the workshop notice. And written comments are due on December 17th.

And with that, I'm pleased to turn it over to Commissioner Andrew McAllister, who's the Lead for the 2021 IEPR. Thank you.

CEC COMMISSIONER MCALLISTER: Well, thank you, Heather. I'm really pleased to be here again. Yesterday we had a great set of workshops related to the forecast and some other work that the Commission staff is doing sort of beyond the forecast, trying to look more prospectively ahead, really, to SB 100 scenarios and things. So, that was very stimulating, and

informative, and really hope that stakeholders submit substantive comments on that.

So, today we have another action-packed day related to supply-side demand response. Really pleased to be joined by Vice Chair Gunda, who is the lead for this work. I've been working with him and the staff team on that.

As well as a real great group of colleagues here at the Energy Commission and the Public Utilities Commission. So, Commissioner Monahan, and I think Commissioner Douglas may be on or will be joining shortly, from the Energy Commission.

And then, we're extremely pleased to have three of our colleagues from the Public Utilities Commissioner. President Batjer, Marybel Batjer, Commissioner Genevieve Shiroma, and Commissioner Darcie Houck. All friends to the Commission and really partners in this important work that we're doing.

I also want to just acknowledge Heather and her team for an amazing set of workshops as we sort of pick up again towards the -- getting towards the tail end of the IEPR cycle and trying to sort of revisit some of the themes that we started on during the summer, and get some resolution on any of the issues that come out. And really, sort of flesh out and make the final product as

concrete, and as useful, and helpful as possible for the state's planning efforts. And today surely fits in that mode.

And the IEPR team, Heather and the whole team really just does such a great job of teeing this up and making it easy for us to participate, and really encouraging staff involvement. And I want to just, again, make the clarion call for stakeholder engagement here. I see the numbers ticking up, we have over 100 people on the line today. And really, we're making every effort to be as accessible as possible so that anyone who has anything to say about this and other topics has the full chance to make their opinions known, either today in the meeting or written comments afterwards on the docket. So, we very much appreciate that participation.

We also have the Public Advisor's Office, who does a great job for providing access to those who are less accustomed to participating. So, all of those resources, hopefully, are going to enable anybody who wants to, to participate.

So, I also want to just tee up the topic before passing the microphone to my colleagues. So, supply-side demand response is a key resource, this aggregated demand response is a key reliability resource that we

need more of in the state. And there's a long history of sort of experimentation and programmatic approaches that have been successful to some extent. And I think with the summer reliability issues that we've had, we're sort of turning over every rock we can and really trying to figure out ways to do better.

And the collaboration with the PUC, with the Public Utilities Commission is, I think, really key to having the kind of dialogue that's going to help us chart our collective path forward.

And then also, obviously, the California Independent System Operator is extremely interested in this.

And I want to just acknowledge all of our partners. Tom Flynn and David Erne, who you'll hear from today, who have really done a great job of sort of marshaling this conversation and keeping it moving forward. And Simon Baker at the CPUC, and Anna McKenna over at the CAISO, who have really taken the lead for those agencies on these discussions, and you'll also hear from them.

So, a wide variety of staff at all the agencies are involved in this, so certainly don't -- that is not the end of the list, but I think for brevity I'll just stop there.

But this joint project, we'll hear, I've been getting briefings, you know, regularly on this and really look forward to hearing the latest today, and working this into the IEPR, and really coming up with some concrete steps forward that we can all apply and implement together.

I think this is a -- the technologies that we have today really do open up a lot of possibilities to making it easy for customers to involve, to get involved in and participate in these programs, and we need to make every effort that we can to rationalize and sort of make as consistent, as possible, the requirements that -- so the customers have an easy path to participation

And on the flip side, so that they are accountable for delivering the committed resource, resources that they make by participation in those programs.

So, we'll hear about all that and more today. And I want to just say thanks for everybody for being here, up to 120 plus here today. So, really, thanks for all the attendees and the participation that you'll have today and in the future.

So, with that I'll pass to my colleague, Lead Commissioner, Vice Chair Siva Gunda.

CEC VICE CHAIR GUNDA: Thank you Commissioner

McAllister. I want to just begin by thanking the IEPR team, Heather and her entire team for putting on another workshop. As you mentioned, yesterday was a very productive meeting specifically looking at, you know, some of the challenges that we might be discussing today. Looking at the future of demand scenarios and then how do we really think about system planning.

I want to also thank my colleagues, both from the Energy Commission, Commissioner Monahan, and I'm guessing Commissioner Douglas is here or will be here soon. But also, colleagues from CPUC, President Batjer, Commissioner Houck and Commissioner Shiroma. Thank you so much for joining. It's always a pleasure to be on the dais together and discuss these important topics.

To kind of set the stage at a very high level, so demand response has been and continues to be a valuable resource for providing reliability, reducing GHG emissions, and managing costs of the electricity system.

However, I think, you know, DR has much greater potential to support these goals than it has been to date. We're experiencing substantial growth in behind-the-meter resources, with a growing potential market to aggregate these resources in ways that were not possible before. And I think we need to maximize those efforts.

Today's workshop is focused primarily on the potential for DR to support grid reliability. One of the main barriers to developing a robust market for supply-side DR is how we measure and value these resources, including their contribution to reliability.

This issue was highlighted during the August 2020 rotating outages, which highlighted the inability of the current system to measure DR's contribution to reliability, particularly during extreme heat events.

As a result of these events, the CEC, CPUC and CAISO have substantially increased the coordination of our efforts to improve system reliability. We also initiative dialogue with the DRPs earlier this year, in deep dive roundtables to better understand and define the challenges experienced last year.

While the result was for the CPUC to request the CEC to help in recommending an improved method to developing the qualifying capacity for DR. I want to just thank Simon Baker, the leadership at the Commission, the CPUC for making this request and both collaborating carefully through this process, but also providing the independence and the leeway for CEC to have its own process play out.

In response to the CPUC request, the CEC convened the working group to reimagine how we do this

measurement and evaluation in a way that grows the supply side DR market in support of reliability, climate and cost goals.

I want to just thank Tom Flynn and Erik Lyon for the incredible amount of work that they have put into convening and facilitating the working group.

And as Commissioner McAllister noted, David Erne and a number of other staff behind the scenes that have been helping with this impact conversation.

The working group has many passionate members. And while, you know, they may not always agree on the approach there is a consistent and a robust agreement on the value that DR can have to support of reliability and other state goals.

I want to thank the working group participants. They have invested a tremendous amount of time and effort to help improve supply-side DR programs, including engaging in weekly 2-hour working sessions since our staff workshop in mid-July.

You'll hear this afternoon about the progress of the workshop, of the working group, including some options for improving methods to value DR qualifying capacity.

The CEC and the working group will have much more work to do and the CEC's anticipating having to set

a class set of recommendations to CPUC in February time frame. So, we solicit public comment and have a final set of recommendations for PUC, as requested.

I also want to take this opportunity to just kind of talk about how excited I am on the opportunities on the load modifying side of the DR, as well. With the leadership of Commissioner McAllister, the state is moving to increase the use of flexible demand appliances and take advantage of those to radically expand the DR capability.

So, I just want to say the load management standards and all the work that Commissioner McAllister is doing incredibly supports this broader DER conversation.

I also want to applaud CPUC's DER Action Plan 2.0, under Commissioner Houck, which will make significant strides to improving load modifying DR through electric rate design. And I just want to thank both the commissioners for their incredible work in this space.

But we also believe that there's a significant amount of work to be done in the near term on the supply side, while positioning the state better to take advantage of technology improvements.

In closing, I just want to say, you know, as we

look through the SB 100 results of an incredible amount of supply-side growth that we require to support the future clean energy goals and the reliability it is almost inconceivable to think about a future without having a broad and robust participation on the demand side. But it's demand flexibility, DR, whatever it might be, in whichever market shape it might come, it's important that we solve this problem especially to deal with reliability and climate crisis.

So, really looking forward to getting an update on where we are and move this conversation forward in a productive and helpful way for the state.

So, with that I will pass it on to my fellow Commissioners, Commissioner Monahan, President Batjer, anybody who would want to say anything.

Commissioner Monahan, please.

CEC COMMISSIONER MONAHAN: Thanks Vice Chair Gunda. And thanks, Commissioner McAllister for setting the table.

Well, I am the lead for transportation and I feel responsible to talk about the role that transportation could play in DER in the future. Right, today it's a trivial amount, but our 2021-27 analysis indicates that compared to today's electricity load the increase could be up to 25 percent in 2030 to meet -- if

we meet our goals for transportation electrification. And that's a huge flexible resource. So, we want to set the right conditions today to be able to capitalize on that load in the future.

We have pilot projects going on here at the Energy Commission, we've funded over 200 school buses that have the power to -- have the ability to give power back to the grid, so call them V-to-G, vehicle-to-grid. And we're trying to figure out how to unlock that value stream so cash-strapped school districts can actually save money as they electrify their fleet, and take kids to school in cleaner buses.

We're also seeing the Ford Lightening F-150, which has the first vehicle, light-duty vehicle that's being advertised as something that you could power your home for. So, it's a resilient strategy. And again, it's sort of just emblematic of the changes that we're going to see going forward in the transportation ecosystem.

So, I'm really excited to learn more in today's conversation. And as you both have highlighted, the importance of resilience can't be overstated. And so, this is a core strategy to make sure that California can deliver safe, clean, affordable energy. And reliable, the most important one.

And it's a pleasure to be joined with so many of our counterparts at the Public Utilities Commission. President Batjer, Commissioner Shiroma, Commissioner Houck, it's really wonderful that you all are here with us today.

CEC VICE CHAIR GUNDA: And Commissioner Shiroma?

CPUC COMMISSIONER SHIROMA: Yes, thank you. I did want to defer to President Batjer, first. Go ahead, if you'd like to.

CPUC PRESIDENT BATJER: Thank you. That's so kind of you, Commissioner Shiroma. I apologize for not being on video today.

I do want to thank my fellow Commissioners, both on the CPUC, as well as the CEC. This is a tremendous effort.

Commissioner McAllister, Vice Chair Gunda, Commissioner Monahan, your efforts, your passion, your energy is outstanding and amazing. So, I'm just very pleased to join this august company today to discuss the important issues surrounding the supply side demand response, as has been well outlined by Commissioner McAllister and Vice Chair Gunda.

And I reluctantly say that I have never in my state government work, I've never felt that it was good to assign a sister agency a task, but that's what we did

here in Decision D21-06-029. We requested that the CEC launch a stakeholder working group process in 2021, in the IEPR process, and make actionable recommendations on changes to the qualifying capacity counting methodology for the demand response. And you have beautifully done that.

And Commissioner -- Vice Chair Gunda, I'm so pleased that you mentioned that the working group report will be submitted in February. I think it was actually due in March. But thank you, if you can submit early, that's very, very helpful so that we consider recommendations as appropriate for the implementation for the 2023 resource adequacy compliance year.

So, I so appreciate the important collaboration among our agencies, among the Independent Systems Operator, and the CEC, and the CPUC. It's been a very important collaboration over the last year, since we hit the rolling curtailments of August of last year. We've all learned a lot from each other.

And I love that Commissioner Gunda mentioned the passionate members of our working group. We do have passionate and very devoted members. And yes, they don't always agree, but we always get to a very good, good place through our collaboration. And we've learned much from each other and we will continue to for the

betterment of the people of California.

So, thank you for this workshop today. And Heather, thank you and your team for all the hard work. I know you've had the metal pressed to get -- the pedal pressed against the metal since last summer, so appreciate it greatly. And thank you for the few minutes to address you all. Thank you so much.

CEC VICE CHAIR GUNDA: Thank you so much, President Batjer. As usual, your comments are always so precise and generous, so thank you so much for setting the stage.

With that, to Commissioner Shiroma.

CPUC COMMISSIONER SHIROMA: Yes. Thank you, Vice Chair Gunda. And to our Commissioner colleagues on the dais, thank you so much to your teams, to the CEC staff for putting together this workshop. It is sure to help us develop supply-side demand response for the resource adequacy program.

And as President Batjer indicated, we trued up this partnership this past June and it is an essential effort in particular to address the CAISO's concerns about whether we've been over valuing demand response to reliability.

And this workshop and the working group will help us in the path forward. Thank you and I look

forward to the presentations and to the comments that follow on. Thank you.

CEC VICE CHAIR GUNDA: Thank you so much, Commissioner Shiroma.

And we'd love to have Commissioner Houck close it out this morning.

CPUC COMMISSIONER HOUCK: Thank you, Vice Chair Gunda. And I want to thank Commissioner McAllister, Vice Chair Gunda, Commissioner Monahan and Commissioner Douglas, who I think will be joining, for inviting us to attend. I think it's been a great partnership between the two agencies and I look forward to continued collaboration and work.

I also want to thank you for mentioned the DER Action Plan and the importance of distributed energy resources. And thank my BK partner on the DER issues, President Batjer, for teeing it up so well for me to take on, when I came on board.

So, again thank you to everyone. And I'm really here to listen and hear more. And I want to thank the staff for all of their work, and the presenters, and especially Heather and her team. So, with that I'll turn it back over to the CEC.

CEC VICE CHAIR GUNDA: Thank you so much Commissioner Houck, and everybody, for the wonderful

comments and setting the stage.

So, the first panel is on reliability and resource planning and kind of setting the stage at a very, very high level. So, I will, you know, really thank Simon Baker and Anna McKenna for being here to help share some of their thoughts. And I'm going to pass it on to David Erne, who will be moderating this panel. David.

MR. ERNE: Thank you, Vice Chair. So, I just want to make a couple comments as we conclude our final workshop and the reliability track for this IEPR. I want to thank all the participants throughout the year that have been participating in all of our workshops and providing insights that were valuable.

As was mentioned previously, the root cause analysis helped to highlight some of the improvements that are needed for reliability. And our workshops have covered all of the activities that have been going on this year among the CEC, CPUC and CAISO to make improvements to the planning and operations. And we've covered those, I think, pretty extensively through the workshops, with the one remaining being supply-side demand response.

And as noted through the comments, the reason that we have this last is to make sure that we can

incorporate as much as possible from the ongoing CEC working group to make sure that that gets into the record, and we ensure the most progress -- or the updates on the progress that we've made. So, it's important that we have this workshop. Timing not intended to apply the priority for supply-side demand response. I think everyone agrees this is an important element to the state's portfolio. But want to make sure that we're incorporating the most current knowledge as possible into our IEPR this year.

So, we've set up our workshop today to really cover this topic pretty broadly. We start with our first panel, which is going to be covering the perspective and the role of reliability or role of supply-side demand response for reliability. And that's going to be described by the two entities that are driving DR primarily with the state, which is the CPUC and CALISO.

And then, our second workshop or our second panel will talk about the DR perspective, the DR provider perspective on supply-side DR to get that incorporated into our discussions. And that will wrap up the morning.

In the afternoon, we're going to be going through a more detailed discussion, a very technical

discussion of the progress that the working group has made to date. Recognizing the working group still has work that needs to be done and wrapped up in the February time frame, so we can get something out to the public on that report, and get some feedback on it before it goes final, and the recommendations go over to the CPUC.

So, that leads us to our first panel and I will set the stage. For this panel, we have two speakers. Simon Baker, who's the Director of Cost, Rates and Planning for the Energy Division at the PUC.

And we have Anna McKenna, who's the VP of Market and Policy Performance from the California ISO.

They'll both be giving the perspectives on supply-side DR from those two organizational elements and particularly as it relates to reliability.

So, at this point I will turn it over to Simon to begin his presentation. To you, Simon.

MR. BAKER: Hi. Good morning Commissioner McAllister and Vice Chair Gunda, President Batjer, and all the distinguished Commissioners on the dais. It's a good showing of Commissioners and we can see that demand response is a focal point of attention for the energy policy leadership in California.

We're really all hands on deck ever since the

events of August of 2020, where demand response was really highlighted as critical for reliability, and was really put to the test. And we are now, you know, focused even more on doubling down on how we can grow that resource. But we need to do that in a way that maintains grid reliability.

So, it's a pleasure for me to be here today. I'm going to be providing a brief overview of the PUC's demand response activities to provide some context for today's workshop. And I just want to say that the collaboration with the Energy Commission on demand response issues in the IEPR has been extremely helpful to us.

We, at the CPUC, obviously have spent a lot of time working on these issues. This particular issue about refining our understanding of the qualifying capacity of demand response really being assured of the reliability of demand response, while also providing opportunities for this resource to grow has been a challenging and vexing issue for us. And we really appreciate the fresh set of eyes that's being brought to it by the Energy Commission. And it's a valuable collaboration.

Also, I'm pleased to be on the panel today with Anna McKenna from the CAISO, with whom we've also been

collaborating very intensively over the years, and in particular on this issue.

So, next slide, please. I'm going to be just providing some background on demand response programs at the CPUC, and then I'll get into some particulars around proceedings and new initiatives with regard to demand response.

Next slide, please. First, some basic definitions around demand response. In the 2017 decision, the Commission broadly defined demand response as " reductions, increases, or shifts in electricity consumption by customers in response to economic or reliability signals."

So, there are different flavors of demand response that we'll be talking about in this presentation. But in essence, it's all about trying to provide value to the grid and also to help to provide contingency value in the event of emergencies on the grid.

So, demand response can alleviate that stress on the grid, reduce operational costs, and play a critical role on grid reliability and price stability, and also help to avoid the construction of new infrastructure. It can reduce fossil fuel consumption and help integrate renewable energy.

The next slide, please. There has been a long evolution of demand response in California, starting from the 1980s when we really only had emergency type demand response.

And then, in 2004, after the first energy crisis, we introduced the loading order which put energy efficiency and demand response first in the loading order as the first preferred resources. And ever since we've been really trying to prefer demand response in the state.

In 2007, we had a big milestone where the state began investing in SmartMeters, which then became the enabling technology, really, for demand response to be more time differentiated and responsive in terms of how rate designs could be developed around demand response.

We began integrating demand response into resource adequacy programs. And we also, at that point in time, made a distinction between two different types of demand response programs, economic and emergency demand response, which I'll talk more about later.

So, with the advent of the SmartMeters we were then able to advance time-of-use rates, first in the nonresidential sector and then, eventually, more recently we've now gone to residential time of use.

Also, in the 2010 time frame the CAISO really

began developing a number of products around demand response, pursuant to FERC orders, and we collaborated really intensively with them on the development of those.

In 2012, the CPUC pursued a strategy to try to foster the demand response, load demand response to market by enabling third-party demand response providers to directly fit in their resources to CAISO markets to be able to run energy ready in the CAISO markets. And so, that led to the adoption of the CPUC's Electric Rule 24 and 32.

And then, in 2014 we took a big decision to bifurcate the demand response portfolio and I'll talk more about that and our reasons for that.

Also at that time, we pursued a pilot program the demand response auction mechanism, which continues to this day. And what that was really about was to be able to provide a capacity payment to third-party demand response providers because we found that it was insufficient to just enable the direct getting of demand response into CAISO markets because the energy revenues were insufficient to really support those market models.

And so, the DRAM [Demand Response Auction Mechanism] is really one of our strategies to try to stand up the third-party demand response market. The

Commission, also in decisions around that time, indicated a preference for third-party demand response and has been trying to foster that market ever since.

I mentioned that residential time of use began -- we had the big decision in the residential rate reform proceeding to move towards default residential time of use. And we are now getting towards the later stages of implementation of that in the utility service territories.

And for the past three years we've continued our work to refine the demand response program design. We're also seeing a new market emerge where demand response providers are able to get resource adequacy contracts with IOU load-serving entities, CCAs [Community Choice Aggregators], such as (indiscernible) -- and that happens to our load impact protocol process, which is much the subject of today's workshop.

So, also recently, as was mentioned in the Commissioner remarks, we sort of relaunched the Distributed Energy Resources Action Plan in what we're calling the version 2.0. So, that the draft of that is out now and I'll talk a little bit about that. And we also have our summer reliability proceeding.

So, the activities in demand response just continue to proliferate and a lot of effort is being put

into it.

The next slide, please. So, in 2014 and 2015, the Commission's demand response rulemaking pursued a strategy of differentiating between two different types of demand response. And really, the impetus of this was initially the CAISO was -- they were calls for demand response to be really more visible to them in their markets. And also, we had a lot of calls for -- from the ratepayer advocate groups to have the demand response resources be more useful and utilized more frequently. And the thought was that by having the resources being made to the CAISO market, they would be dispatched more frequently.

And so, the demand response portfolio was split into supply-side demand response, which is dispatchable demand response resources that are integrated into the CAISO market and counted for resource adequacy.

And those resources are compensated for capacity by the load serving entity with contracts with the load serving entity, and then they receive energy payments in the CAISO market if they're dispatched.

And so, examples of these programs include like AC cycling, and the capacity bidding program, and also the interruptible program and the AG [agricultural] pumping program.

On the load modifying side, these are programs that are not classified as supply-side DR. They're typically time variant rates. And the load reductions for these programs are counted in the CEC's IEPR forecast. So, they're kind of on the forecast side of the bookkeeping as far as the load and resource balance goes.

And the compensation typically occurs through bill savings to the customer. And examples here include time of use, which I mentioned earlier, and critical peak pricing, and others as well.

And this is an area of demand response that we're really hoping to grow in future years.

The next slide, please. So, I mentioned that we view supply-side demand response as two main types of programs. The first is economic demand response, which is triggered by price signals in the CAISO market. And so, these resources may participate in the CAISO market as proxy demand resource, PDR.

Among the programs that bid into this mechanism is A/C cycling and capacity bidding. And then, there's also contracts that the IOUs have to acquire local resource adequacy, these local capacity requirement contracts. And so those are bid in that load, they bid on climate, also bidding through economic DR. As are

the LSE contracts for DR under RA, as I mentioned earlier.

The second type is emergency DR. They'd be triggered by emergency grid conditions and may participate in the CAISO market for the reliability demand response resource. And in these two types there are the base interruptible and agricultural pumping.

Next slide, please. So, looking at our current portfolio of demand resources of the utility program and the non-utility programs that are PUC jurisdictional. And I should have mentioned at the outset, these presentations just, you know, they are about the jurisdictional programs. The publicly-owned utilities have their own programs, but that's not really in this slide presentation.

So, in terms of supply-side demand response for 2021, we had about 1500 megawatts of demand response when we look back in terms of project qualifying capacity. And in there we have the AG managed demand response and third-party managed demand response.

So, for the IE program it breaks down to, now, something like 1200 megawatts. I figured the emergency programs, which are about 800 megawatts. And the economic programs which are about 400 megawatts.

And then, the third-party managed portfolio is a

combination of the demand response auction mechanisms, so that's a little over 200 megawatts, and then the CPA contracts with DR under this RA construct, which are about 120 megawatts.

And then on the load modifying side we have about 85 megawatts of demand response there through a combination of the time of use, and critical peak pricing.

The next slide, please. So, this is kind of getting a little bit to the heart, I think, of today's workshop, which is that different types of programs have different aspects with respect to whether they are included on the CAISO's supply plan, which is something which the CAISO seeks.

And we see that the demand response program and the third-party CCA contracts, they are on the supply plan, but currently these programs are not. And so, the CAISO has been requesting for us to find a way for those resources to get on the supply plan, so background. And this working through processes to see if we can achieve that.

And each of these different program types have different methodologies for determining qualifying capacity. And principally, the current method is the load impact protocols which is a process by which the

performance of a resource is evaluated based on its post performance and then it is submitted for review to determine what the core forecast and state value should be.

The next slide. So, I think I'm going to skip this slide, the demand response auction mechanism and how it works is as noted here.

The next slide. And the demand response auction mechanism, as I noted, it's been going on for some years now. It's still in the pilot stage because evaluations have been made which had some mixed results, and revised, and reformed over time seeking program improvements. And there's an evaluation study that's underway right now and it will be reviewed in the forthcoming proceeding.

But we can see the megawatts and the dollar values that have been budgeted here.

Next slide. So, I'm going to run through a number of different proceedings. So, demand response is currently being -- the policy is being developed.

The next slide. The summer reliability proceeding where, pursuant to the Governor's proclamation on emergency provisions coming out of the DEA. This is a new proceeding which we've been developing a number of different new pilots and

strategies, and there's some innovation that's happening in this proceeding.

One of which I want to point out, in the phase 1 decision which we adopted earlier, where we developed an emergency load reduction program. This is a voluntary pay-for-performance program with no CAISO market obligation. And it's not counted for RA and it's not in there for load forecasting. And the CEC is kind of more to continue to resource but we think that we can learn a lot from that pilot that could potentially be then translated into other DR program designs.

And then, just yesterday, we adopted a phase 2 decision in that proceeding which adopted refinements to the year of two programs including increasing its compensation $2 per kilowatt. And also adopting a number of different pilots in there, as well as modifications to the programs.

So, in this proceeding has really been nothing that's to move quickly, and innovate, and take some risks and find out some different things on demand response.

The next slide, please. One of the things that I want to highlight under that decision just yesterday is that we are testing out an outlet for virtual power plants that's started by the Load Reduction Pilot

program.

And what this is, is it's an aggregator managed behind-the-meter hybrid resource consisting of storage paired with NEM [net energy metering] solar. And this is some on of the -- some of the rules with this pilot are that the resource cannot be part of a market integrated DR program. Got the minimum size threshold.

But what's kind of unique about this and what we're testing for the first time is that net exports by the resource are providing compensation. And that there's a lot interest in the marketplace to test this out and get a Commission decisions have been very keen to see innovation-based, so we'll give that an opportunity to test this out.

The next slide, please. The main proceeding with meritocracy programs are reviewed is the application proceeding, which is currently on a five-year cycle. And then next application period 2023-2027, IOU programs are to be submitted in May. And so, there will be significant policy development that will be developed there, including their potential future of the demand response option pilot.

And then, in the resource adequacy rulemaking for supply-side demand response there are a number of different RAs and rules which are pertinent to the

supply-side demand response. As was mentioned earlier, that's the rulemaking on which was requested the CEC to help us to review the qualifying capacity methodologies that we'll develop in this whole working group process.

The next slide, please. And as was mentioned earlier, so we did issue a draft of the DER Action Plan 2.0. And it gives some insights into possible directions that CPUC will take at this point. It's at staff approval.

It has four different tracks on it. And two of them are really certain for demand response. So, this is Track One, load flexibility and rates. And in there, staff recommends the development of a load flexibility rulemaking, which would really expand on that load modifying demand response, and try to achieve more of the potential that we believe is there for that.

There was a workshop back in May where we previewed a staff proposal on that. And we're working really closely with the Energy Commission, for sure, on the load management standard rulemaking, which we believe is an important to plan into the strategies that we're recommending the Commission proceed in that realm.

And then, in Track Three, which is really about more the market integration and supply-side demand response, we're recommending more at the rulemaking.

And some point in 2022 to combine supply-side demand response with storage policy, and to perhaps emergencies there.

And then, finally, in general rate case proceedings, in the Phase 2, GRCs of the retail loadings, we had a series of proposals that have come forward. And beginning with San Diego, the decision, there were some dynamic, great pilots that were proposed there and they're being considered as well for the PG&E GRC proceeding that's ongoing right now. So, that's definitely something to watch as well.

The next slide, please. So, thank you so much for the opportunity to present here and I'm looking forward to the rest of the day.

MR. ERNE: Thank you, Simon, for the detailed overview of the programs and setting a good stage for the discussion today, as well as updates on PUC, and all the activities going on there.

So, I'll turn it over to Anna McKenna to give the ISO perspective.

MS. MCKENNA: Good morning. Thank you, David. Good morning everyone. I wanted to start by thanking the Commission for this series of workshops and inviting us to participate in today's discussion on supply side demand response and its importance on grid reliability.

Thank you, Vice Chair Gunda, and Commissioners McAllister, and Monahan, and Douglas for your leadership in this area.

I also wanted to thank Commissioners -- well, President Batjer and Commissioners Houck and Shiroma for participating today.

And I especially want to take this opportunity to thank you all for yours and your teams' collaboration, guidance, and contributions in helping the ISO navigate this past summer successfully. We had some exciting moments, but I think we did good, so thank you.

Thank you, Simon, for your excellent overview of the lay of the land on demand response under the PUC programs. I want to say and share with everyone that it's been a pleasure. It's a pleasure for me to be on a panel with you today and have an opportunity to share with everyone some of the challenges, and thoughts, and ideas we've shared over the past year to enhance demand response participation on our grid reliably.

And although our work is not done, I'm very appreciative of both the CPUC's and the CEC's careful consideration of our reliability challenges, especially after last summer's events.

As we all have noted today, after August 2020

events we all recognized the critical role demand response plays in helping us operate the grid reliably. And with the increased presence of viable resources in extreme weather conditions, we all recognize how critical it is that we get this right soon.

I'm going to share with you today the ISO's perspective on what is needed for grid reliability and valuing supply-side demand response, and our efforts over the past year to further these goals.

So, for the ISO demand response is and will continue be an important resource as we work towards meeting load reliably in an increasingly decarbonized grid. The ISO has worked over many years and has our market platform to integrate demand response resources fully, being able to dispatch them, and compensate them for energy and ancillary services through our markets.

Our hope is that we can rely on demand response as an economic resource, fully integrated into the ISO markets with appropriate incentives, and compensation for customer responsiveness. Being able to measure and harness the benefits that such responsiveness provides to the grid reliability.

As Simon mentioned earlier, currently we have two market models for demand response. One for resources that are dispatch in response to market

clearing prices. We refer to those as PDRs [proxy demand response]. And one for resources that primarily provide reliability services. We refer to those as RDRRs. And if you can say those two things fast ten times, you might get a star. And the secondary category, the RDRR, represents about 72 percent of our market integrated demand response.

So, you know, we continue to evolve these models almost on a yearly basis, fine tuning them to ensure that they meet our market needs, as well as recognize the load capabilities of demand response that we see on the system.

From a resource adequacy perspective, you know, we've been advocating to enhance the planning assumption so that the resources that are secured for resource adequacy meet our reliability needs. And to get this right, we strongly believe that we need better RA planning assumptions for demand response.

And, you know, there's been a lot of discussion in the workshops, in the CEC workshops about what those might look like. But we've highlighted that what we need for our purposes is that the planning assumptions should use respected and accepted industry-leading practices that recognize the variable output nature of demand response. We've asked that they assess demands

with response contribution to reliability across the year or seasons. And we've asked that they assess demand response interactive effects with other resources. Because as you increase the amounts of similar energy and use of the resource, these add less and less capability, additional capability value on the system because of the interactive effects.

So, we don't believe that the current planning assumptions that are used in the RA programs today and the load impact protocols meet these requirements. And we've had a lot of discussions about that and I want to share with you some reasons why.

You know, we think the load impact protocols do not consider the use limitations, limited energy or the variable nature of most demand response in establishing the qualifying capacity, also known as the QC values. They fail to account for the reliability impact when you have a saturation of use limited resource on the system. Therefore, we don't think we can assess demand resources actual contribution on reliability.

The lift is more relevant when the resource adequacy program's primary concern and target was to meet those peak capacity needs, but that's no longer the primary concern on our system. You know, at that time energy sufficiency was non-issue because there was lots

of gas, and nuclear, and hydro resources that could support system energy needs. However, circumstances have changed dramatically and we know that to be all too well. We know that too well at this point.

So, this may be a useful tool for estimating hourly operations abilities, but we're not confident it's not -- now, as we're operating the grid that it can actually reflect the capabilities that we actually need for reliability.

You know, over the past year, as well, we have been participating in numerous efforts with the PUC and the CEC. And we are asking -- we're asking for demand response and the changes that we're asking for evaluation of demand response. You know, we don't think our significant deviation from some of the changes that have been made in the RA program to address similar concerns with other resources. Indeed we have seen capacity evaluation to be a critical issue in all the reliability discussions. And we can see value submitted by the load serving entities and their supply plans inform the ISO's ability to meet our operational and reliability needs.

While the original RA plan was designed to meet peak load in each month, plus the PRN, as the grid has evolved with increasing penetrations of intermittent

resources, and use-limited resources, capacity evaluation has to now also consider and better capture the reliability contribution of these various resources.

So, you know, recognizing this need the PUC, for example, has already updated its capacity evaluation for wind and solar using what is known as an ELCC methodology, as well as for hydro resources to reflect potential drought conditions in their valuation.

In the PUC's IRP proceeding, the ELCC is also applied to four-hour duration storage resources. And the ISO has most recently proposed a counting methodology to reflect in the specific outages.

So, all these efforts are part of the need to articulate actual reliability contributions on the grid of these resources. But demand response counting hasn't changed until now and this is the question before us is how do we do that.

And we also have been working to transition, and Simon noted this earlier in his presentation as well, and I wanted to share some thoughts as to why we've been doing this. You know, we've been working to transition away from having demand response that is not on supply plans and, instead, is credited against a load serving entity's resource adequacy requirements.

You know, our goal has been to transition these

resources onto the supply plans to ensure that they're counted in a way that reflects their impacts on reliability. And that is because resources that are not on supply plans are not really visible to the ISO, on our systems, and this means that they are not checked and verified to see they are following their RA requirements, such as through their must offer requirements that we impose on resource adequacy resources.

And in essence, this means that although the demand resource may not be available as we had planned for them to be available, they're still getting their capacity credit for being there. The problem with this, of course, is that if the DR resource was counted to meet a load serving entity's resource adequacy requirements that means other resources are not procured to meet that load serving entity's requirements. And then, this displacement means that the DR resource -- if the DR resource is not available in the operational time space well, we don't have anything else to meet the LSE's load.

And that's a simplistic way of looking at it. I understand there's a lot of, you know, variations around that. But in essence, that is the issue we have to try to address is make sure we have the resources we need to

meet the load.

Resources that are supply plan -- on supply plans and subject to must offer requirements are also subject to what we refer to as RAAI, which is the resource adequacy availability incentives mechanism, and it's a form of an incentive. It's really more of an incentive mechanism and it has penalties associated for non-performance as well.

And the concern is, of course, if they're not on the supply plan and not subject to RAAIM, there may not be incentives in place to ensure they're available.

But there has been a concern raised and we have considered and recognized this very carefully that, you know, if a variable resource is variable because of reasons beyond its control then, you know, they shouldn't be subject to the penalties.

So, what we think and what we have done is that we think it's important to align the counting of the resources up front with their performance. And so, if you can align those two things more closely, then any variability from those two elements is really beyond their control. At that point, then that resource should be exempt from that penalty.

So, we've already asked our Board of Governors for permission to file a tariff that where, if DR

resources are valued under a counting methodology that accounts for their impact on reliability more accurately, then they should be exempt from the RAAIM penalty. We haven't filed this, yet, because pending the outcome of the CEC workshops and the CPUC proceedings, we'll see what we have in terms of accounting methodology for next year.

So, consistent with this goal, you know, we have been pursuing two paths to improve DR counting and performance. The first is, and central to today's discussion, is an improved methodology for counting DR's contribution to reliability.

We've been very supportive and I actually want to take a moment -- I should have done this earlier. I'll take the moment now. I want to really thank the CEC for the working group efforts. And I want to thank, for the CPUC's initiative in collaboration in asking the CEC to help us on this important question.

You know, and I also want to call out and thank both Tom and Eric for their great work in leading this effort. It's been a real pleasure to work through this with both of you and all of your team.

So, in this effort the CAISO has been proposing that we consider what we refer to as the ELCC methodology, which we believe better accounts for the

impact on reliability of demand response resources.

Most recently, together with PG&E, we've been putting forth a methodology which we refer to as the LIP profile informed ELCC. And that, we think, is a way to reflect, better reflect the DR's variable use limited and availability limited nature.

We don't think this is necessarily, you know, a perfect way of doing things, we understand. However, we do think it is an improvement from today's valuation. And we do want to encourage moving towards that so that we can get ourselves ready to, hopefully, quantify and qualify the resources for RA year 2023.

So, you know, one of the things that we also have been discussing with participants in the workshops and sharing with you all is that, you know, we don't think the ELCC approach is a revolutionary or new approach that is -- you know, that -- we're pretty confident about it because it's a well-accepted, industry-wide approach that's being increasingly used across the country by other ISOs and RTOs for evaluation of use-limited resources, and has already been applied to wind and solar resources quite -- you know, quite significantly.

It hasn't been applied to demand resources as of yet, but we do think this may be yet another instance in

which California will be leading when it comes to demand response, so that we can better support greater integration of demand response reliability on the grid. And we're keenly interested in enhancing demand response participation reliability

So, we're hopeful that this can be tested for RA year 2023 and can lead to further refinements, and inform the program that design that is immediately available for IOUs in 2023. It's an option for IOUs in 2023 and it could also actually help provide insights into how this may be used for others, third-party providers.

And we also think, you know, that based on what we have seen so far that this could be a viable option for us to then perhaps enhance the program further for subsequent years, given the experience we would have with the first year.

So, again I want to summarize that we do feel confident that the ELCC meets the criteria that we've been articulating with respect to the elements that we need for reliability in a counting methodology. And we're hopeful that it will materialize over the next few months.

So, the second effort I wanted to spend a little time on today, it's not the subject of today's

discussion because this goes more towards the measurement of DR's performance in our market, and in response to dispatches in our market. And that is improvements of DR measurements through a controlled group methodology for establishing baselines for demand response for both participation and settlement in the ISO market.

Well, and this, I'm sure, you've all heard about a little before, but let me just spend a few minutes on it. You know, in response from stakeholders earlier this year and after the August 2020 events, where we had articulated a certain responsiveness of the demand response resources. We noted that there were improvements that could be made in the baseline approaches.

So, we worked with Recurve to examine how effective the control group methodology could be in measuring demand response performance. What we found is through that report, we were able to conclude that control group approach is an accurate method to see the impacts of energy use curtailments and, therefore, is a more accurate method for compensating providers.

We're excited about these results because this provides an improved baseline approach which is consistent with our current tariff requirements and,

therefore, can be immediately available for those who choose to use it.

Now, we do recognize that there are currently some barriers to accessing the data, but we view the outcome of this effort, which has prevented some parties from endorsing and adopting this methodology immediately, but I think there's been discussion underway to work through some of those barriers.

But we do view the outcome of this effort as evidence that a better methodology for assigning demand response value does exist and it's a starting point for longer discussions with the PUC on how to integrate into the CAISO settlement process.

This is a subject different than we have here today. But I wanted to thank you for indulging me a little bit on that item.

So, with that I wanted to say thank you again for having me here today and I look forward to a continued discussion on all these topics today, and in the future.

MR. ERNE: Thank you. I just want to say thank you to Anna and to Simon, both, and I'll turn it over to you, Vice Chair, for questions and comments from the dais.

CEC VICE CHAIR GUNDA: Yeah, thank you David.

And thank you Simon and Anna for kind of setting the stage on this.

I think, you know, I kind of want to -- I mean there's a lot of questions here and I think we're going to dig into the details throughout the day and, hopefully, in future workshops as well.

But just at a very high level I think, you know, just thinking through a 30,000-level kind of a principle. I think, you know, we kind of talked about SB 100 goals, near, medium and long term reliability challenges for the State of California, and the importance of the demand side elements to be a part of the solution.

You know, Simon, you kind of showed a table with some of the kind of the DR numbers and how it has been changing over time. And, you know, Anna, you kind of talked about the challenges from CAISO's point of view on ensuring that, you know, some of the reliability numbers that we kind of show, you know, that the numbers are, you know, comfortable, are dependable.

So, I think what I wanted to see is if you both can comment at a very high level how do we expand DR? You know, I feel like there's so much here that we -- I don't think, you know, as I mentioned in my opening comments, I don't see a plausible pathway moving forward

where DR doesn't become a large part of the stack to really ensure we are doing, you know, resource planning and reliability in a cost effective manner.

And I think Commissioner Monahan kind of talked about the V2G element, you know, which is going to be the next big element that, you know, we're going to talk about in the DR side and the DER side.

So, from your perspectives, you know, from your years of experience in this area what should we do from your perspective, and from your organization's perspective on where we go from here. Maybe starting with Simon and then Anna.

MR. BAKER: Great, thank you, Vice Chair Gunda. You know, the PUC, in our decision not too long ago, some years ago, really looked to third-party demand response as a source of growth for demand response. And the DR Auction Mechanism Pilot was really set up to try to foster that market.

What we found in evaluations over time is that we've had to continue to tinker with the rules and that model to have the assurance that we're actually getting the reliability out of that resource, that it's actually being utilized, that it's actually being dispatched, that it's performing.

We've had some performance results that have

come in, frankly, from the DRAM Pilot that have been not so good. And that goes a little bit to some of the topics that Anna brought up in the second part of her presentation, and I'm glad you mentioned that Anna, about the baseline methodologies and the work that's going on there.

And so, it gets into the nitty-gritty of the accounting rules in the operation space, and then also, you know, the nitty-gritty of accounting rules in the planning space. And we've heard from the third-party demand response providers that both are kind of issues and are problematic. And, you know, that they seek a change.

And at the same time we are state agencies, you know, we have to stand by the principles of, you know, ensuring that these resources are, you know, being scrutinized and reviewed for their reliability contribution. So, that's the tension that we're trying to work through here.

I think there's a lot of promise in this opportunity that we have, actually, that came out of the August 2020 events, where the emergency reliability proceeding is now basically putting a lot of effort, and resources, and money into new pilot program designs that are outside of the RA construct and the DR construct.

So, in essence you can think about it as kind of like a safe space for experimenting with some new program designs to see if things like virtual power plants, and others, can contribute and be shown to perform reliably. Because there's a bit of a chicken-and-the-egg problem that happens with demand response. Because on the front end the demand response providers want to be able to basically be qualified for a bunch of capacity so that they can get, you know, capacity payments for their resource. But if they haven't yet, really shown that the resource can perform, I think that the agencies are reticent to go ahead and just like, you know, give them a bunch of advanced qualifying capacity credit.

And so, how do we break that chicken-and-the-egg cycle? I think some of the experimentation that's going on and out of the emergency reliability is going to be very helpful.

And the last point I'll make is that at the staff level, at least for some time, we think that there's a lot of support with our Commissioners as well, we see the direction of heading more towards the, you know, load modifying demand response and less on the supply-side as really a common direction.

The challenge is going to be how do we continue

to allow the existing market models, which are based upon supply-side demand response and integration in the CAISO market, how do we allow for those to (indiscernible) -- even as we develop a new pathway through load flexibility, where we can greater participation of new resources such as the electric buses that Commissioner Monahan was talking about, and other, you know, devices type of strategy.

So, that's really kind of, I think, the vision that we have is to continue to troubleshoot, frankly, because there's a lot of issues that we had in launching new supply-side demand response in the CAISO markets. Continue to troubleshoot those issues, and while we also build a new form of demand response through the load flexibility rulemaking that we're recommending, and through the Energy Commission's load management standards rulemaking.

MS. MCKENNA: Thank you, Simon. I'll make some comments. And thank you, Vice Chair Gunda for your question. It's a really important one, obviously. One that's easier to -- easy to say, but harder achieve, if you will. So, please take my comments in that, you know, in that regard. I don't want to sound too glib about this, you know.

But at a high level, obviously, aligning the

costs and benefits, you know, of the programs to us through a grid reliability perspective, for the ISO at least, the more we can align those costs and benefits, and the more we can count those resources, or see and materialize -- the value of these resources materializing on the ISO's ability to operate the system reliably, the more we can, you know, embrace those resources on the system.

So, you know, from a simple perspective, you know, aligning those costs and benefits is sort of a primary task.

Now, getting to that, as Simon suggests, is a complicated, you know, element. And the programs are, in California, quite extensive, and diverse, and they do -- it does require looking at each program differently in order to address how you increase participation.

But one of the things I wanted to share is that, you know, over the past year I've had some opportunities to talk to demand response providers, and we'll get to hear a little bit from them later today. But, you know, there is a vibrant and interested segment of the community that does believe that there is a good opportunity, good, viable business opportunities for the, you know, demand response participation.

I think part of the challenge is making sure

that the compensation and the incentives are correct so that you're compensating for the products that you're actually receiving on the system, and the value of that resource. And as Simon was suggesting, you know, even with the baseline approaches that we had to improve over this -- or we're looking, seeking to improve, those can be real barriers, those types of rules, if you wish, or formulations could prevent an ability for those program -- or, demand response providers to go out and, you know, thrive as business enterprises.

I am a firm believer that having a market environment to provide those kind of incentives is important. But working through those detailed linkages between what is going on, on the grid, and what is going on in the programs across the system is going to be the challenge. I think in a simple way that's pretty much the challenge we have to address.

The other thing I've had an opportunity to do most recently and, you know, I think we stand to learn perhaps, is that there are a lot of programs in the rest of the country viable as demand response programs. And so, we're looking to see, you know, what are they doing? How are those programs sustainable? Because I think that may be helpful for us to also gain some, you know, additional knowledge in terms of what's worked

elsewhere. And, you know, we'll be looking at that more and encouraging that for others to look at as well.

But I think overall, the challenge from a rate base perspective, and ensuring as well for our -- the load serving entities that have to bear the costs, if you wish, or they're burden with some of these programs, making sure that there's a right compensation, as well as the right discipline in the programs is going to be part of that challenge as well.

So, I think we can achieve it, but I think we have to be diligent in aligning those incentives.

CEC VICE CHAIR GUNDA: Thank you, Anna and Simon. I think, you know, I have -- you know, your comments kind of precipitate a lot of different questions and I would have loved to kind of jump in more, but I think we're running a little late. So, I would want to pass the mic on to Commissioner McAllister and Commissioner Monahan who is here on video, if they have any comments or questions.

CEC COMMISSIONER MCALLISTER: Yeah, thanks Vice Chair Scott (sic). And I was going to ask -- well, I still am going to ask a smaller question, now. Simon, you started to answer it. But it gets to this question of the sort of boundary layer, the boundary line between, you know, load modifying and supply side. And

so, as we move toward rates, and I'm really happy that everyone is -- you know, that the load management standards is on everyone's radar, and seen as a really key platform there. Because I could be very transformational to grow that, as you referred to, Simon. To get, you know, a lot of just routinely modifiable, you know, manipulable loads doing that to, you know, improve capacity factor, improve load factor all around, which helps optimize the grid and reduce costs, et cetera. So, I think that there's a lot of promise there on the demand side, the load modifying, sort of permanent load shift kind of realm.

And so, you mentioned this is sort of problematic of how much that might cannibalize sort of the supply side and I think that's a natural tension.

And I guess I'm wondering if you have anything sort of additional to say about as we move towards more dynamic rates, and really happy to have all of these conversations happening in the DER Action Plan, that's going to be huge, and I think it's a really great sort of place for us to collaborate further. You know, as you start, certainly with time of use, you know, that's sort of firmly in the load modifying.

As you move towards dynamic rates and even real time pricing that starts to look like more event driven.

If those rates kind of flow down in something approaching real time.

And I guess I'm just wondering where -- so, if that's kind of on the radar to kind of figure out when that boundary looks like. When an economic DR moves from one side to the other in terms of, you know, load modifying versus supply side.

MR. BAKER: Yeah, I mean we actually, in the bifurcation decision and in our decision to clarify some of these issues, you know, the PUC made, you know, made kind of the technical definition of load modifying being, you know, responsive to one that's non event based, with one small exception, of course, the critical peak pricing. And that really got to, I think as you know, you know, a way of actually trying to quantify the megawatts of that and get that into the -- you know, in the resource adequacy accounting paradigm and, you know, working with the CEC to kind of count those critical peak pricing resources kind of on the demand forecast side of the books.

So, there's -- so technically, well, I think what happens is that as we go more and more to the dynamic rates, and real time pricing, you know, the thought process is really that the revenues that demand response providers, and that then flow through to, you

know, customers as built in benefits which are being provided now mostly through capacity claimants, which is, you know, the main revenue source on which the demand response providers depend and that they then, you know, compensate their customers and customers receive bill savings.

That, you know, the theory is really that then the real time pricing benefits on, you know, the most critical days can provide those revenues.

Now, the market model, though, it really does have to change. And this is the part of the conversation that hasn't really happened yet, and we need to have it. And I think the DER Action Plan and the load flexibility rulemaking that we've envisioned is that we think that that's probably the home where we have these conversations.

But we have to, you know, really hear from the DR marketplace of how does that then work? How to move from a construct in which you have RA capacity payments that are kind of like the main revenue source to some other construct where the DR providers, they still have a viable space in which they can, you know, provide value to the customer to make it seamless for the customer, and yet still have steady, predictable revenues that come in to, you know, support their

business and to provide benefits to the customer.

So, I think that's the conversation that we need to have and that hasn't happened, yet.

CEC COMMISSIONER MCALLISTER: So, does that begin to take the shape of sort of rate design principles at some point, like advice or direction to the utilities about how they should be structuring -- or at least a conversation about how they should be structuring their, you know, dynamic trending rates? Because that seems like that's where the rubber hits the road, right?

MR. BAKER: That's exactly right. Yeah, and I mentioned the staff proposal that we previewed with stakeholders back in May, in a workshop. There's kind of a six-step plan that we've developed to go about this and it really does, it envisions having value streams coming from, you know, generation capacity, but then also from, you know, distribution capacity as well, and having that be location and time differentiated. And the challenge is how we really develop those methodologies, but we think there is a way through that.

CEC COMMISSIONER MCALLISTER: Great. Well, that's going to be a great way to -- a great platform for collaboration going forward. And so, there's a lot riding for that and I'm really interested in getting it

right. So, thanks for that.

CEC VICE CHAIR GUNDA: Thank you, Commissioner McAllister. I'm short on time, but I really want to give a quick minute to Commissioner Monahan if she has any comment or question, but would love to move to the next panel, or the Q&A.

CEC COMMISSIONER MONAHAN: Okay. I'll try to be fast. I wasn't here this morning, so I'm excited to ask the question around will the DER Action Plan really set the stage for transportation electrification opportunities in DER? And when I say that, I think about these three aspects, there's V2G, then there's flexible charging. And the flexible charging has two components, it's when you charge and how you charge, right.

We're seeing EVSE -- we're seeing charging providers starting to build in solar and storage as a way to minimize grid costs, but that's also a DER opportunity that could be unlocked.

And I'm just wondering will that DER Action Plan encompass all those opportunities in the vehicle space?

MR. BAKER: Yeah, certainly that's the vision. And I'd be happy to follow up with you, Commissioner Monahan, perhaps with a briefing on the DER Action Plan where we can go into it.

CEC COMMISSIONER MONAHAN: I would like that, yeah.

MR. BAKER: One of the elements, one of the cornerstone proceedings that actually does kind of -- the data -- the proceeding for one of the tracks, which is the great integration track, where the DER, a high DER feature, OIR Commissioner Houck is actually the assigned Commissioner for that. And that really is all about how we plan on the grid to maximize the value of these energy resources and, in particular, high electrification.

And so, we're pursuing a number of strategies there to ready the grid and take into account, you know, how we forecast the charging patterns of electric vehicles. And then, it's going to be working in close concert with the load flexibility rulemaking, which is I think really where the, you know, the DR benefits of these new storage resources and load sources on the grid, where they can be harnessed.

CEC COMMISSIONER MONAHAN: Thanks Simon.

CEC VICE CHAIR GUNDA: Thank you, Simon. I don't see any of the PUC leadership with cameras on, so with that I'll pass it to David, for the Q&A.

MR. ERNE: Actually, it's Erik Lyon is going to be doing the Q&A.

CEC VICE CHAIR GUNDA: Oh, thank you. Great.

MR. ERNE: So, Eric, do you want to come on and -- we're pretty limited on time, so I think we'll just limit it to one question so we can get to the next panel pretty quickly.

MR. LYON: Yeah, we have a question from Jennifer Lu from SoCalGas. She noticed it looks like there is an anomaly in the amount of capacity involved in DR in the 2019 . It looks like it may have decreased in that year.

Simon, if you could quickly comment, is there any reason that you know of that DR capacity would have decreased in 2019, after generally increasing?

MR. BAKER: Yeah, I'll have to get back on that. I don't have a specific answer there.

MR. LYON: Okay, thank you.

CEC VICE CHAIR GUNDA: Eric, maybe we want to take one more question.

MR. LYON: Let's see, maybe a question from the same person, who is also wondering if you could provide DR capacity for the last ten years, or maybe you could just give us a sense of how DR capacity has grown over the past decade.

MS. MCKENNA: I think that question was for me?

MR. LYON: Sorry, that was also for Simon.

MS. MCKENNA: Was it for Simon? Okay.

MR. LYON: If you have an answer to it, we'd welcome it.

MR. BAKER: Yeah, we have -- it's grown and shrunk. And part of the challenge there is that we -- you know, even as we've kind of doubled down on efforts to grow the resource, we've also been doing a lot to work on, I'll say, kind of improving the quality of the resource and utilizing the resource more.

And we're finding our methods for quantifying, you know, the contributions, and so forth, and so that has, you know, resulted in some downward adjustments, frankly.

We also improved the rules around the use of backup generation from fossil fuels, which was our policy that the Commission adopted to prohibit that in demand response resources. But it took some time to develop an enforcement mechanism and so that actually resulted in kind of a downward bump, with some customers losing programs as a result of that.

And so, you know, as to the question that was mentioned earlier, the future areas that we see for growth are in third-party demand response and, hopefully, in rates and load flexibility demand response.

And I can also do a follow up to provide more specifics in terms of what the numbers have been historically, up to today.

MR. LYON: Okay, thank you.

MS. MCKENNA: This is Anna. I wanted to perhaps add a little bit, at least from what we have seen through our markets which, you know, may not be the complete numbers. But we have seen through our markets, from 2014 to 2021, we've seen demand response grow from zero to about 3.6 gigawatts. So, that's, you know, a good amount of growth in our markets of demand response.

CEC VICE CHAIR GUNDA: Eric, it looks like there's a lot more questions coming, but I apologize to all the attendees that are asking questions that we don't have time. Hopefully, you can stick around to make a public comment or cover these questions as we go forward.

With that, I would like to move on to the second panel and welcome Tom Flynn to kind of take over this panel, and he'll be moderating that. Tom.

MR. FLYNN: Thank you.

CEC VICE CHAIR GUNDA: Oh, Tom -- thank you Simon and Anna. Thank you so much for your presentations, and wonderful comments, and being able to, you know, articulate the questions and answers here.

So, thanks so much to both of you.

MR. BAKER: You're welcome.

MR. FLYNN: Thank you Anna, and Simon as well. Appreciate your gracing us with your presence today.

Thank you, Vice Chair Gunda and everyone on the dais. Hello and welcome. I am Tom Flynn, with the California Energy Commission and I'll be moderating this next panel.

We arranged this panel so that we could hear from a range of stakeholders who participate in demand response, so that we could hear their perspectives on demand response opportunities and issues in California.

I'd like to welcome our panelists, our three panelists and thank them for being here today. Allow me to first introduce all three panelists and then we'll give each of them, in series, the floor to provide their perspectives.

First up will be Jennifer Chamberlin. Jennifer is the Executive Director of Market Development for CPower Energy Management. Jennifer will provide us with a demand response provider, or DRP perspective.

Up second will be Paul Nelson. Paul is with Barkovich & Yap, and he is here today in his role as a consultant to the California Large Energy Consumers

Association, also known by the acronym CLECA. Paul will provide us with a demand response participant perspective.

And then lastly, up third will be Chetna Smith. Chetna is Senior Manager of Demand Response Program Management for Southern California Edison. Chetna will provide us with an Investor Owned Utility perspective.

Each panelist will have approximately eight minutes to provide their perspectives. After we hear from all three panelists, we'll then open it up to discussion and questions from the dais.

Jennifer, please begin, the floor is yours.

MS. CHAMBERLIN: Hello and thank you so much for having me this morning. I've decided to throw my prepared remarks out the window based on the conversations we've had thus far today. So, if I'm a little less polished, I'm sorry, but I want to kind of respond and give our perspective.

So, CPower is a demand response provider, as Tom shared. Around the country, operate around 4 and a half gigawatts of load flexibility. And a very small percentage of that is within California.

We see in California that load flexibility, so customer buildings, and then their behind-the-meter DERs are, and I'm pleased to hear it this morning, and thanks

to the Commissioners that have laid the groundwork on this, that it's a really key element in achieving our decarbonization goals.

And, you know, California's kind of on the forefront of a lot of what we see the entire country and the world facing in the future, a much more intermittent and renewable grid. One that's facing climate challenges, that needs to harden itself against whether that be inclement weather, and more in other parts of the country, and wildfire here. So, a lot of very big cost drivers.

And we think one of the best ways to keep things, you know, keep prices under control, as well as to provide resiliency is to have the harnessing of the load side, whether that be through load modifying resources, or supply-side RA, and actually, it will need to be all of the above, are really critical elements to be able to do that.

And so, as a DR provider, you know, what I'm hearing from a question this morning is what is it going to take to grow demand response in California. And this is something that we have struggled with as a company. And I've spent a number of years, I lead our policy and market development efforts at CPower in both California and in Texas, so two grids with really significant

problems we're struggling to overcome, and that need to figure out how to make the demand side work and grow. Because both states, while they have very different policies and politics, have really strong levels of renewable penetration and really important grid needs that we need to drive towards fulfilling from a reliability stand point and a resiliency stand point.

And so as, you know, we can get out there and simply look at the challenges we face, California is kind of -- has one of the smaller demand response markets. You might have noticed that outside of kind of these utility emergency programs that aggregators can participate in, there's really only, you know, about 350 megawatts of kind of economic demand responses participating in the markets, which is a really small percentage compared to other places, in a place where see the biggest grid needs.

And so, from our perspective we keep looking at this and saying how do we fit in here and how do we make this work? And so, there have been a couple of challenges.

One, you know, we work primarily in the C&I space, particularly in California, but I know that there are residential folks on the phone and that I've been, you know, sharing thought leadership with for a long

time, and that we support residential demand response programs in other parts of the country.

So, to have, you know, a place like this to run a business, you do need revenue certainty. A revenue opportunity certainty. The revenue certainty comes when you bring a resource to the table and it performs and that's what you expect it to.

What we have struggled with in California is a lessoning of options to provide that avenue of revenue. Primarily, that comes through capacity payments. Because we don't have a robust services market, either. The energy markets are depressed. We've tried as a state to keep our energy markets depressed. We don't let there be super high pricing, we don't want to see that, and that's a policy decision and it's fine.

But then, there's the revenue opportunities largely come from access to a capacity payment or access, perhaps, to a flexibility service market that should need to exist, a more robust ancillary services market, or those sorts of, you know, ramping products on the load side.

We don't have those, yet, and I think, you know, as a complement to capacity those are a really reasonable way for us to go and to explore.

And the reason I say we've had limited capacity

opportunities, as a DR provider we've had programs shut down. We had aggregator-managed portfolios that are no longer in play. And then, we've had the demand response auction mechanism stymied in some extent from the budgets that we spent on it.

And we are still very challenged in qualifying stand alone RA capacity. The mechanism to do that has only been available for a short period of time. And it's one that Anna talked a little bit about before, about the load impact protocols, and others have mentioned this.

The load impact protocol, as a way of qualifying capacity, is a bit of a unicorn across this country. I think it made some sense when you were looking at all the things within an IOU portfolio, where you've got weights, you've got load modifying resources and, you know, wanting to know what the interactive effect of these things are. I mean the load shape's for planning. And, but this is a multi-part progression analysis that takes a look back, and assumptions for the future.

We went through our study for the first time to qualify, you know, a relatively small portfolio of resources to be stand alone RA. It's about $150,000 of external like pure dollars, and then significant, significant internal time, with an uncertain outcome.

It took us about eight months from start to finish. And we need to start that right now for 2023. Those need to be in by the end of the year. And this process is, I'd say, long, expensive, and painful. So, it's one that we'd like to see moved away from.

I understand that on top of whatever your qualifying capacity might be, that you might need to look at something like an ELCC. We're open to that sort of thing, but you need to have an underlying qualified capacity.

We need to have ways that recognize that all these behind-the-meter customer DERs are the vehicles that are coming into play. These are much more dynamic. These aren't the stationary resources. And both the market structures and the qualifying capacity structures need to recognize that dynamism of them.

These resources are one of the quickest ones to get up, and harnessed. And then, the slower ones to qualify for capacity. So, I'd say that's really, really important from a DR perspective, provider perspective.

Additionally, I'd say Anna made some great points about the measurement of these resources and making sure that they recognize the actual contribution. As a provider in summer of 2020, we found that our resources worked all out. And frequently, with almost

no curtailment based on methodologies we've used. We've been participating in CAISO's efforts, and appreciate them, and think that there are better methodologies as we get to the point where customers need to be a point of -- a significant part of balancing the renewables on the grid, and providing that flexibility. Having methodologies that aren't so backwards looking, and that better proxies for what would have happened absent their interventions are going to be really, really critical to harness the demand response.

And, therefore, from our perspective, you know, we need to have fast ways to qualify capacity. We've said that we can bring resources to the table in times of great stress. We need to be able to measure them accurately and reasonably. We don't want to over -- you know, we don't want to over promise and under deliver. My company strives to bring things to the table that will meet reliability needs. But, you know, we're looking for a way to grow that and have the certainty in the future.

Thank you for the opportunity to talk about these things today. I appreciate it.

MR. FLYNN: Thank you, Jennifer, very much.

Next up is Paul Nelson. Paul, go ahead.

MR. NELSON: I want to thank you for inviting me to speak on behalf of customers participating in the demand response programs. And just real quick, can people hear me okay?

MR. FLYNN: Yeah, we hear you fine, Paul.

MR. NELSON: Okay, great. So, the next slide, please. So, CLECA is an organization of high load factor customers located throughout California. The members are in the cement, steel, industrial gas, pipeline, cold storage, beverage, food packaging and mineral processing sectors. Some of the members of the bundled customers of the utility and others are direct access or served by community choice aggregators.

All members participate in the Base Interruptible Program, or BIP, which is available to be called 24 hours a day, 7 days a week. And as Anna mentioned, BIP is a reliability DR program as opposed to what's been classified as a proxy demand resource.

The year 2020 was especially challenging for the members because the program was called five days in a row in August and two days in a row in September, for a total of seven events. When industrial customers respond to an event, the manufacturing or delivery process stops. It is not as simple as turning off air conditioners.

In 2020, BIP provided 845 megawatts of load reduction, which is about 75 percent of the total event-based demand response programs.

And then, CLECA members provided a significant portion of the BIP load shed. And they have a very good and demonstrated record of responding when a program is called upon by shutting down megawatts of load with either a 15 or 30 minute notification.

Southern California Edison has called the BIP the gold standard for demand response.

The next slide, please. The basis of demand response are a triple win. First, demand response helps maintain grid reliability by reducing load during critical periods so other customers do not suffer from rotating outages. If rotating outages do occur, then the number of customers subject to outages is reduced. This is naturally a reliability win.

Second, DR is non-firm load, which reduces the need for additional costly capacity that is required only during exceptional peak events. And a DR participant, the incentive helps offset the very expensive electric rates in California.

And then, economic DR allows for increased supply stack, which can avoid the purchase of more expensive energy. This is a cost win for all customers.

Third, the industrial electric rates are twice as high in California as compared to nearby states. The state competitive business customers that use a lot of electricity could choose to move production outside California and some already have done that.

And the DR incentive helps offset California's high electric rates and keeps businesses in California. When an emission-intensive business stays in California, it produces products with cleaner electricity, which reduces GHG linkage and avoids increased GHG due to the transportation of goods into California. This is a carbon win to meet climate change goals.

The next slide, please. It is important to have an accurate measurement of the load reduction provided by participants in a DR program. The CPUC has established the load impact protocols which uses statistical methods to forecast expected load reductions based on past events and test event performance.

The current measurement focuses on a load reduction during a monthly peak between 4 to 9 p.m. This measurement period covers the gross peak, as well as the evening net peak which is a growing concern, as Anna mentioned.

In my opinion the load impact protocols do a very good job of estimating the utilities' DR program

load reduction during those periods of concern. Although, improvements can be made to speed up the process and reduce costs by eliminating reports that may not be necessary.

The CAISO is recommending the use of an effective load carrying capability, or ELCC methodology that would incorporate a measurement of a DR program's ability outside of the current 4 to 9 p.m. monthly peak. That can result in derating the load reduction estimate compared to the load impact protocols. It is not clear why DR programs would be called during nonpeak time event periods. So, at least certainly not for reliability programs.

The ELCC methodology would add enormous complexity to the process, making it difficult for customers to understand why their potential peak or net peak load drops are being discounted.

Even more concerning is the proposal would add enormous complexity, which also would significantly increase the cost of the DR counting method. And Jennifer expressed some concern about the cost for third-party DR providers.

Since DR program cost is subject to cost-effectiveness test, if the cost of measurement is neither successive, then DR incentives would have to be

reduced for the DR program to pass those tests. Lower DR incentives will result in lower DR participation.

So, in sum on this issue, the ELCC method will result in increased generation procurement due to the combined effect of lower forecasted load drop and lower DR participation.

The next slide, please. The CPUC is redesigning its Resource Adequacy Program to ensure sufficient resources are procured not just for the peak, or even the net peak, but at other times of the day and across the time of the year.

The CPUC adopted a concept called Slice of Day, which will be implemented in 2023, for the 2024 RA compliance year.

The CEC workshop effort should focus on a DR accounting methodology that is consistent with the Slice of Day design and, as I've already discussed, being mindful of cost.

Some parties have proposed to implement ELCC in 2022, for the 2023 compliance year. In my opinion, the ELCC proposal is incompatible with the Slide of Day approach. And PG&E's proposal in the Resource Adequacy Forum would replace the ELCC method that is currently used for wind and solar, with its much simpler exceedance approach.

The ELCC approach, as I mentioned, would add significant cost and complexity to DR measurement. Furthermore, adopting ELCC for a one year interim period is not a good use of stakeholder effort.

To summarize, to achieve the triple win for reliability, cost and climate change goals is accomplished by advancing customer participation in DR. To achieve that increased participation, DR program design needs to be understandable by customers and with sufficient incentives while maintaining program cost effectiveness.

To maximize the incentives, the cost of program measurement sheet balanced with the appropriate necessary accuracy. And the focus of the CEC workshop process should be on an accounting method consistent with the Slice of Day and not be distracted by interim approaches.

Thank you very much for my opportunity to address the Commission.

MR. FLYNN: Thank you, Paul, appreciate that.

Our next panelist and last panelist is Chetna Smith, with Southern California Edison. Chetna, go ahead.

MS. SMITH: Thanks Tom. Good morning everyone, thank you for having me. As part of my segment, I'll be

highlighting SCE's Minding the Gap white paper that was recently published, specifically in the area of demand response. I will cover challenges with DR programs, as they're integrated into the market. And SCE's exploration of a longer term vision of pulling DR programs out of the market, starting with our next DR application cycle.

Relating back to the current RA proceeding, I will address SCE's position on the equitable and fair valuation and treatment of DR resources represented in policy areas.

And then the final point on the stakeholder working group and a pass forward for DR/RA counting.

A little background on my career at Edison. I've been with the company for 15 years and have spent time in IT, power procurement and customer service, specially in the areas of electric vehicle operations, business customer division and now, for the past two years in demand response program management.

Although I would say I'm fairly new to this subject area, compared to a lot of my colleagues on this panel, and in this audience, I'm excited to share with you my thoughts and the company's vision on how demand response plays a critical role in ensuring safe and reliable service, and the steps we need to take as we

transition to a decarbonized future.

If you've had -- if you've not had a chance to read it, SCE's Mining the Gap white paper was recently published, provides analysis of the policy changes and additional actions needed to ensure that California meets its goal of reducing greenhouse emissions 40 percent by 2030.

There is a section that describes the long term vision for demand response and the principles to achieve a dependable customer-centered portfolio for grid reliability and advancing a clean energy future.

A few things to note about the sections that are relevant to the topics shared this morning, utility level demand balancing programs focus on the customer and distribution grid to achieve net peak shaving across applicable hours, while minimizing customer fatigue and leveraging technology in automation.

Demand response rates and programs must be designed with the end-use customer in mind. Programs must be kept simple and easy to understand. Utilities must be transparent with customers on what to expect from the participation. And translating complicated market integration rules, requirements and baselines to the customers, a barrier to success, and scaling enrollment especially in the residential section, or

sector.

Fundamental customer mind shift starts with the consumers of electricity as a result of building trust, ensuring consumer protection across all classes, and increasing awareness and accessibility for energy end-use options.

Demand flexibility is key for a reliable and clean energy future and this includes storage -- this includes storage and connective devices to support future demand response potential.

Today's technologies can add to the current mix of DR programs focused solely on emergency grid shutoff responses to help mitigate peak demand, while also minimizing and not affecting customers' comfort or business operations. Traditional DR programs can be retained for infrequent use for true system emergencies.

If you want to learn more about the white paper, I'm happy to share a link with this audience.

To date there have been questions and challenges on the way DR resources have performed and been accounted for, particularly for our RERRs.

On the issue of wholesale performance, which was discussed earlier, SCE agrees with the CAISO and parties' comments on DR performance values that have been limited by baseline methodology characteristics and

not due to underperformance of the resource itself.

We understand that there's more analysis that's being done in this space and we look forward to the findings and committed to working with CAISO, and the other parties to remedy the baseline methodology flaws that continue to have the undervaluing of the performance of DR.

Additionally, you can see the same type of undervaluing in the Root Cause Analysis Report that was done from the 2020 event, particularly in Figure 4.5. Overall, this shows that IOUs' emergency programs as underperformed against the credited actual meter drop.

One takeaway that we have shared in reliability proceeding, in our testimony, is that SCE's emergency programs outperformed statewide reported totals for all of the IOUs in every except two, on August 14th. And again, you can read more about that in our reliability proceeding proposal -- or testimony.

In many ways, DR has been asked to solve capacity shortages and grid impacts due to climate change. And with all the recent priority of DR in proceedings, we still haven't attracted as much as we could. And we need to take a look at the rules around supply side, updates to system processes to adapt to the changes of DR since we first integrated.

We should take our learnings, visualize together on a common objective and make sure this is effective for every stakeholder in the industry.

This is a critical time to change directions and identify a route that is easier for customers, so they're eager to support California during grid emergencies that we anticipate in the future.

In this environment and climate, businesses and customers are more concerned about their daily objectives versus supporting the grid. As the grid evolves and increasing availability of therms and smart grid technologies, so as the treatment and utilization from demand response from regulations that were built around traditional generation resources, not variable resources, like DR.

While we are -- while there are good intentions for IOUs to integrate these programs into the market and fall under the RA rules and hours, the result of this decision has chipped away the value of DR, customer participation and satisfaction, and has created operational challenges.

As California progresses towards a clean energy future, demand response role is ensuring safe and reliability service to all customers -- all customers, as clear given the increased demand through

electrification. Customer trust and engagement with the management of their energy use through DR is critical for the successful achievement of a clean energy future.

They will play an increasing role as we focus on our satisfaction and it should be a priority in establishing policies in the DR arena.

As a long term vision, SCE will be considering removal of certain DR programs from the CAISO market. If we do this, the vision will be laid out in a phased approach in SCE's next application, which will be filed in May of 2022.

I know we're coming up on some time, so I'll try to move this quickly. While we work towards the longer vision, demand response programs continue to reside on, as they reside on the supply side, SCE like others is looking for equitable, mature valuation of treatment of DR resources represented in policy arenas.

Although this topic is for the afternoon session, one final point in terms of the stakeholder working group and the path forward for DR/RA accounting.

SCE has indicated its position on the valuation and treatment of DR resources in procedural comments during this past year's RA proceeding. While SCE appreciates the collaboration and stakeholder input, it's unclear if the path forward will be decided in time

to meet RA 2023 compliance. Additionally, what the outcome will be for 2024 and beyond.

We will continue to be an active participant in this process and we look forward to the proper methodology that supports this reasonable treatment of DR statewide. And the outcome of this process should be applicable for all DR resources participating in the wholesale market. And while this process, in the bigger context of the RA proceeding should illuminate the best way to count RA credit on the DR supply side, it might also highlight the greater extent of resources that should not be on the supply side and return to the balancing load modifying level.

That's all I have for now. I appreciate the time. And thank you for joining -- or, thank you for having me join this panel.

MR. FLYNN: Thank you, Chetna. And thank you to all three of our panelists.

I think we'll move on to questions and comments from the dais. Vice Chair Gunda?

CEC VICE CHAIR GUNDA: Yeah, thank you so much, Tom. Thanks to Jennifer, Paul and Chetna for your comments.

You know, before we go into the discussion, I just want to, you know, acknowledge all the work that

each one of you through your associations and, you know, a number of other IOUs' analyses that really helped keep the lights on last year and this year. We've hit you with notifications as short as 10 minutes and asking for your response in helping the state keep the lights on. So, I really appreciate all the work that you've done to kind of support the state. And I just want to keep that in the back of our minds as we move forward in this discussion.

So, you know, this was a really good panel. I mean it's really good to hear the thoughts. I think some of the things, Jennifer, we discussed all the way back earlier this year during the roundtables coming off of the 2020 events. You know, we talked about the issues with the complexity, with making some of these programs accessible and understandable to the consumers, but also kind of the certainty. You know, I'll kind of define it as more on the appropriate incentives and you kind of called it the revenue certainty. And I think there's a bunch of these elements that are absolutely necessary moving forward.

So, you know, in the spirit of kind of being, you know, vulnerable and putting the things on the table as we move forward, you know, we need -- I think, you know, as Chetna pointed out, we need to kind of get to a

resolution, you know, hopefully by 2024 or so, in a much, much broader aligned, you know, programmatic and accounting recommendations.

But for 2023, I wanted to kind of hear your perspectives. I know that we are going to go to that later today. But when we talk about revenue certainty, and I just want to kind of hold onto that one a little bit because both Paul and Jennifer, you kind of mentioned this. You know, how do we both, you know, kind of going to the previous panel, ensure that whatever we are showing in terms of the DR is something that is dependable.

And I think what Simon and Anna kind of mentioned, the kind of difficulty in understanding, it's a chicken-and-the-egg problem, you know, how much resources do we have and really kind of -- then kind of being able to account them properly.

So just at a high level, from your vantage point, how do we ensure that we're both showing a dependable value, right, and then two, how do we make sure we also ensure the compensation is equitable to the participants?

So in my mind it's a simple, simple thing, like maybe it's completely over simplistic, but I think of it as if I have an X amount of revenue that I need I have,

you know, a kilowatt drop times the compensation value for the capacity. So that you have two variables there, you know, if we reduce the overall capacity that is shown you still have the economic, and energy markets really make money, but is it just as simple as increasing the capacity value.

So, I just wanted to put it on the table to just understand where we go from here a little bit more from both you. And Chetna, please comment as well, if you'd like to.

MS. CHAMBERLIN: I'll chime in here. Thank you for asking that question, I think it's a good one. And I'd say, you know, it needs -- I would call it revenue certainty, I would call it revenue opportunity certainty. And that's because revenue certainty makes it sound like you should get paid no matter what happens. And I think what becomes very important is that you get paid for what you deliver.

You know, right now we have a lot of chicken and the eggs. We have questions about how you qualify capacity, how you then have the opportunity to sell it and what that would look like. In a lot of markets, I know we don't have a centralized capacity market, so that makes it a little more complicated. But DR providers come in, they essentially collateralized DR

that hasn't been proven and shown up in past years.

So, and then they get paid afterwards. So, when your test year events, your performance comes into play. And so to me, I think the fact that we do so much up front analysis and incur so much up front cost, essentially for resources that also are existing and have been shown to deliver, and evaluate that, we really need then to have a structure where instead we can -- and I find it, you know, put some money on the line in this, you know, and not get paid, and pay penalties if they don't show up. We need to get the measurement and verification sides right on the after-the-fact.

And then, we've got to just say this is what it's worth and you only get paid if you preform. And if you didn't perform or you performed, you know, at a pro rata basis there's less payments. And I think we see that in other markets and we see it in some of the DR programs that from a pure DR resource in RA, which is where all the growth is, we've been -- you know, DRAM has been capped, programs have been eliminated, this is really where we are being pushed to as supply side dispatchable resources.

So, you know, I'd say that not having to put everything up on the front to prove your resource and, instead, use models like New York, and PJM, and others

do for how to qualify these resources, and then make sure the payment on the back end is really just for what was delivered. And that's kind of how I'd put into that. That protects ratepayers, gives customers that opportunity to say this is what I would earn, but I have to perform. And again, you do have to have measurements that work for that.

And I appreciate Anna's efforts and the CAISO's efforts in partnering. We work with them closely as well, and with Recurve to try and see if we can get better measures, especially as these resources are used more frequently.

So, kind of actually long-winded, but I think that's how I would advise it to work. And that's what, in markets that do those things, we see DR play a much bigger role as part of the supply stack.

CEC VICE CHAIR GUNDA: Paul?

MR. NELSON: So, I'll speak, I'll reference I think to the utility program. So, your third question is making sure DR is a dependable value.

You know, Anna mentioned the CAISO's RAAIM which has been an incentive mechanism. I don't think that there's value in that, where it works very well for Dr.

I think the utility programs, there's two things that sort of can ensure DR participation. One is the

fact that they're regulated by the Commission and so, if those resources are not offered and placed in the market, they're subject to review.

And then, I think in terms of individual program DR design, now in the case of the Base Interruptible Program there's actually a penalty if the customer doesn't comply with the call to reduce down to their firm service level.

So, the combination of those two things, I think, will get you to make sure there's a dependable value.

And then the second one, to ensure compensation is equitable, I mean at least in the case of the customers I'm representing, you know, they are recognizing all of the sudden the value of their demand response is in great demand, and there's a lot of cost going into acquire that and making sure that they're receiving, you know, the value. And the good news is, you know, recently the Commission has increased the compensation levels for BIP. But it's really, you know, maintaining and making sure that those, at least the utility programs are, you know, reflected to what's the actual, you know, cost of these capacity valuations and the value of their offering.

CEC VICE CHAIR GUNDA: Chetna, I don't know if

you wanted to comment?

MS. SMITH: Yeah, I think just one overall comment is, just based on what Jennifer and Paul are talking about, that this really does start with our customers and understanding where they're kind of bottom line is and where they're willing to participate.

And so for us, like throughout these new programs that we've offered, which is the ERP, we've increased the incentive, we've increased the kilowatt hour, the incentive point. But we weren't seeing as much participation. For whatever reason, the complication of the integration rules and dual participation restrictions, you have prohibited resources policies that are in place with the Commission, but then we have executive orders that come out that might change that, but adds a little confusion on when to use it.

So, I think we need to be a little bit more streamlined in our approach with customers in the programs we offer so that it's well understood, so we can get that dependability back. Because we see the participation, it's just sometimes it can get complicated.

CEC VICE CHAIR GUNDA: Thank you, Chetna.

Commissioners, I'm going to just have one more

question and then I'm going to pass it. I mean there's like so much here.

Just kind of making sure, I think this goes to the comment that Paul made, you know, just kind of in terms of how often the RDRR was called last year, and it's about almost seven times last year. And the difficulty that it puts on the grid customers in terms of, you know, their availability to move the manufacturing, or the economic impacts of that.

So, just wanted to get again, you know, at a high level, you know, thoughts on this from all of you, but definitely Paul. You know, if we are talking about demand response being used more, and more, and more, right. So, if our hope is to have DR be, you know, essentially balancing the grid on a regular basis and, you know, you have certain times where you have, you know, the reliability needs of DR might amplify. Are we -- how do we make that happen, right? I mean are there certain sectors or certain customer types that we should think about differently, in different buckets? And, you know, if you have any thoughts on that as we move forward towards our climate goals.

MR. NELSON: So, to respond, last year with respect -- you know, being called seven times in a year and five days in a row, you know, for a company that's

trying to manufacture and deliver a product to their customers was especially problematic. And, you know, and the reliability standard is supposed to be one day in ten years.

And so, yeah, they're looking at it for a projection of whether they're going to participate in the program. And fortunately all of them did, they continued. They realized that perhaps 2020 was a severe anomaly and they also saw the actions being taken by the CPUC to address, you know, the resource mix.

But getting to you thing as to use DR more to balance the system, I mean we do have the reliability program, the base interruptible. And I'm not sure that, as a reliability programs is going to be used to, you know, balance the system every day. You're going to really reflect to go more towards economic DR.

Now, I know that in the case of our programs we have not had -- there's been a removal of the dual participation because there is some of their load that could be offered on an economic basis but, unfortunately, right now the rules really don't allow the dual participation between reliability and economics. So, I think addressing and looking at those to remove that barrier would be helpful.

CEC VICE CHAIR GUNDA: And Jennifer and Chetna,

if you want to comment or --

MS. CHAMBERLIN: Yeah, I mean we have recognized and CPower has customers in the base interruptible program, but we also have them in DRAM and the capacity bidding programs, and we've recognized the increased utilization particularly of the capacity bidding program and, frankly, DRAM as well. And we've been building resources and working with customers on their curtailment capabilities that allow that more frequent dispatch.

The measurement approaches, you know, constantly looking back at a 10-in-10 do make that challenging from a baseline, you know, and recognizing a performance. So, the more that we can get away, you know, really and just setting control groups that as third-parties with access to, you know, nonparticipants, we have all of our customers are participants. So, you know, getting access to these other mechanisms.

But we've been trying to build resources that can handle that day after day. And that's one of the things that I think as aggregators we bring to the table. But it has created different uses of customers.

And so, you know, I think we need multiple kinds of programs that have different parameters so that different customer capabilities can be aligned with

them. That's one of the things we find really necessary and useful.

MS. SMITH: I think I would just add it's the chicken-and-the-egg, the fine balance between customer fatigue and, you know, dispatching more to meet the reliability need and what's the right answer there.

And at the end of the day, we can't treat DR like, you know, a traditional resource that we can call upon in these times of emergency over, and over, and over again.

You know, and last year was a very extreme year and I know we're planning for 2022 and 2023, but this year BIP was called once. I know other programs were called, but it was called once in July, at least for SCE. And so, how do we set the right expectations with customers and then get the dependability that we're really looking for.

So, it is a collaborative, you know, discussion between stakeholders and the industry to find the right answer.

CEC VICE CHAIR GUNDA: Thank you, Chetna. I know that -- and Jennifer and Paul, thank you so much for your responses. I think it's really helpful as we think this through.

So, I would pass it on to Commissioner

McAllister, I know he had a question.

CEC COMMISSIONER MCALLISTER: Really sensitive to the time, I know we're already over and maybe Heather can advise us on how far over we can go.

But this question's really for Chetna. I guess, you know, you mentioned sort of the natural order of things, right, sort of returning to, you know, being more intentional and making sure that the sort of permanent load shifting load flex side of things sort of enabled to be all it can be, right. And ratemaking, and price devices is all part of that and not really part of today quite so much.

But I guess you also mentioned DERMs and I guess I'm interested in your kind of feeling about -- well, knowing how you're using DERMs today and how you could enhance their use, or if you could enhance their use to do more of this sort of living, breathing, grid management on the load side that we were just talking about, right. Not like calling seven times, but actually sort of having it incorporated as a resources in all moments of the grid, right, just like any other dispatchable resource.

So, I guess I'm interested in, well, Vice Chair Gunda mentioned this, and I see Mike Florio also has a question along these lines, you know, different

customers are going to be able to -- different sectors are going to be able to do different things. And I guess I'm interested in sort of what you can do with your customers with DERMs, even if it's in real time. Like active management of some category of loads. You know, maybe it's even frequency response or those kinds of services. I guess I'm interested in sort of your expanding a little bit on what you could be using DERMs for that you're not already.

MS. SMITH: Sure. So, I wish this was one of those moments I get to call upon my friends in our Distributed Energy Resources Group, but I'm happy to discuss at least my perspective on it.

I know that we do have the systems in place today and we're trying to get to a place of getting to granular levels of being able to manage the load locally. And then, using like all the resources with customers to provide that type of data to make accurate decisions around our planning.

There are investments today, that is part of our white paper that we've shared, that are happening over the next couple of years to even get more of an idea to help build our programs and contracts to use our DERM system to have that better type of capability, and provide that answer to CAISO and other agencies that

will help with the planning activities.

So, I think that there's more. I mean DERMs has really, over the last few years have really -- maybe not the last few years. Like over the last like five years or so, like really evolved into something. And I think we're just trying to take the opportunity now to understand how it could help with some of this planning, with load modifying resources or, you know, taking things off the integrated path and moving it into a place where we can still use systems like that today, to help with the planning side of things.

CEC COMMISSIONER MCALLISTER: Thanks for that. It's good to hear there's a lot of potential there and I think, you know, you're well placed to really do that granular manipulation that you're talking about. So, great, thanks for that.

MS. SMITH: You're welcome.

CEC COMMISSIONER MCALLISTER: That's it for me, I'm going to just -- I think we could go on for a long time unless we're mindful of the time.

CEC VICE CHAIR GUNDA: We should have had just a single panel. I'll go to Commissioner Shiroma, I think. Commissioner Shiroma, please.

CPUC COMMISSIONER SHIROMA: A quick question for Chetna. You said in your presentation that from the

Edison perspective, CAISO is undervaluing the capacity. Could you just say, briefly, what is the specific quantitative attribute that causes Edison to conclude that. And I know you're keeping in keen mind Anna's presentation about everything the CAISO has to consider for the grid. But isn't there a specific attribute to the supply side DR effort that concludes you to believe it is being undervalued?

MS. SMITH: Sure. So, and just to maybe clarify in my talking points, specifically about the Root Cause Report that had come out in terms of what we had gotten from our RA crediting to what we saw in our actual meter drop specifically for SCE, and the performance that we did back in 2020.

So, I think that undervaluing is where we saw our resources or our customers perform in our program seemed to show a lot more positively than what was actually showing in that report itself. Just based on our load impact protocols and what we saw in terms of our 2020 results.

The other one was specifically the baseline methodologies where we are working through that with the CAISO and other stakeholders on determining the right way of our weather sensitive programs, and looking at the methodologies of how we actively calculate those

baselines. Because we did see some undervaluing of those specific resources for our program.

CPUC COMMISSIONER SHIROMA: And is that to the report?

MS. SMITH: There is the CAISO Root Cause Analysis Report. There's also what we filed as part of our reliability proceedings.

CPUC COMMISSIONER SHIROMA: Yes, for -- so Edison's response?

MS. SMITH: Yes.

CPUC COMMISSIONER SHIROMA: And maybe you could put that in the chat?

MS. SMITH: Sure.

CPUC COMMISSIONER SHIROMA: Thank you. All right, thank you everyone. Thank you very much. Thank you, Chetna.

MS. SMITH: You're welcome.

CEC VICE CHAIR GUNDA: And again, thank you so much to the panel for taking the questions from the dais.

I'm going to pass it on to Eric Lyon to go through the Q&A that came through the chat.

MR. LYON: Hi. This is Eric Lyon, from the CEC. Mike Florio had a great question here.

"Do we need different approaches for individual

customers who have to shut down processes versus temperature-sensitive customers who may only have the load to drop on the hottest days when the system is most stressed? The latter may have little value on average days, but a lot of value on the days when the system is tight."

MS. CHAMBERLIN: You know, we probably do. As I think about how we harness load flexibility, you know, it needs to be an all of the above. And we, in California, try and, you know, go for a lot of precision and try and standardize things. But I think that's not the way we're going to get to where we want to go.

I think, I've just been on a panel with Commissioner McAllister, he's laughing, and I say it frequently, let's not let the perfect be the enemy of the good. And good keeps the lights on and usually at a reasonable cost.

So, I think we probably do need multiple ways to do this.

MS. SMITH: Yeah, I would agree with Jennifer. I think, you know, we have different segment, different programs for different customer segments, and the methodologies that we use should be evaluated specifically to those types of customers and the way that they perform for us.

MR. NELSON: This is Paul. I think both Chetna and Jennifer, you know, expressed it very well, yeah. DR, there's different forms of DR and what they can offer and there may be different forms of a way to utilize them. I mean it's not one-size-fits-all.

MR. LYON: Excellent. Thank you to our panelists for answering that question.

That is the only question in the Q&A, so I will turn it back over to Tom Flynn.

MR. FLYNN: This is Eric. I think we're -- I think to Heather's team, we're moving on to public comment now, is that right?

MS. RAITT: Yeah, this is Heather. So, yes, thank you everybody. And so, we'll go on to public comment and Dorothy Murimi is available, from the Public Advisor's Office, to help with that. So, go ahead, Dorothy.

MS. MURIMI: Thank you very much, Heather. So, just a few instructions for everyone. One person per organization may comment and comments will be limited to three minutes per speaker. If we do have several parties interested in commenting, we may reduce the time to accommodate everyone.

Now, if you're using the Zoom platform, use the raise hand feature. It looks like a high five and it's

located at the bottom of your screen or device. And if you're on the phone, go ahead and press *9 or dial *9 to be able to indicate that you'd like to make a comment. And then, *6 to unmute on your end. And we'll unmute on our end once we call out your name.

And finally, once your line is open go ahead and state your name, and give your affiliation if any.

So, I'll start with folks on Zoom and then move on to folks on the phone. And if I do mispronounce your name, apologies. Go ahead and again pronounce your name and give your affiliation.

I'll start with Amaani Hamid. Amaani, your line is open.

MS. HAMID: Hi, thank you. This is Amaani from Leap. Thank you so much for organizing this panel. I'm really happy take part in the discussion and to see the discussion.

There are two challenges that I think need to be included in this discussion with regards to how we scale and improve the reliability of DR resources. The first is data access. One of the biggest barriers faced is our access to reliable accurate and on-time data. And in order to improve DR and in order for DRP to pay customers on time, to be able to evaluate performance quickly and make any changes necessary as quick as

possible, we need to improve the data accessibility issue. And that should be folded into this conversation about improvement for our supply-side and load-modifying data -- or DR.

The second is creating a level playing field between IOU DR and third-party DR. I do see DR has become much more onerous and prices have decreased over the years, while IOU programs such as CVP have higher capacity payments, and are much easier to participate due to fewer requirements.

If IOUs' pilots are approved and are able to use cost recovery tool to pay higher premiums to customers, but third-party DR continue to struggle to get credit for one tool up for a battery storage site, for example, then we need to ask ourselves if we're really setting DR, and specifically third-party DR up for success. Thank you.

MS. MURIMI: Thank you, Amaani.

Next we have a caller and the phone number is ending in 385. Again, phone number ending in 385. Unmute and state your name.

MR. UHLER: This is Steve Uhler. Can you hear me?

MS. MURIMI: Yes, we can, Steve. Yes, we can.

MR. UHLER: This is Steve Uhler, U-H-L-E-R.

I'm interested in the data accessibility for the customers. Since the customer's in the driving seat of any demand response, they would be making the choices of whether or not to even join a system like this. You need to have better real time data. Some customers are going to be interested in only buying green energy, so they're going to want to move to those areas and that could help out with loading by storing their energy in washed clothes, or whatever else that they make or such like that.

One thing that comes to mind is the customer will really be in the driver's seat where the rubber meets the road if Ford and Purdue University come through with their greater than 1 megawatt charge system. That will be for every thousand cars charging that way that's a gigawatt.

So, you know, and the Cal ISO, maybe they may take all 45 gigawatts that are available just in charging, you know, some 32,000 cars in this state.

The other thing about demand response is it becomes normalized. You talk about fatigue, people don't want to do it or they just give up because it's too hard. But if you get one that's in there solidly, you may forget about that and not realize that somebody else is coming in because of the lower electricity price

to just take that up.

So, yeah, a big point would be, and the Energy Commission's in the driving seat on this, power content level. Let's make them a daily. There should be no reason, if you can do this demand response kind of data system, you should also be able to tell all the customers exactly where their power came from.

The SB 100 shuffling, let's make sure that we're not shuffling things here and making it appear to achieving such things.

So, I live in Sacramento County. We have no wind power here. The wind that's owned by SMUD is sold to PG&E. Very little solar. Very little renewable. Even some of the solar that's in the county is balanced by the Cal ISO. Which I'd like to thank the Cal ISO for at least -- at least handling those products for us.

So, yeah, once again as an energy user, I want to see real time data. I want to see it sitting on my desk here. And I want to know exactly what I can do. And I want that to happen for all of the 39, 40 million people in this state. Thank you.

MS. MURIMI: Thank you for your comments, Steve.

Next we have Mike Florio. Mike, your line is open, you may begin your comments. State your name and give your affiliation, if any.

MR. FLORIO: Yes, this is Mike Florio. I was just thinking to myself and not (indiscernible) --

MR. MURIMI: Mike, we're having a little trouble hearing you.

MR. FLORIO: Oh, okay. Can you hear me now?

MS. MURIMI: Yes, that's much better. Thank you.

MR. FLORIO: Okay, thank you. We need to think more harder about the residential air conditioning opportunity here. I mean we all know that it's AC load that drives our peaks and creates the stress on the grid. But, you know, as a customer I just got my electric heat pump a couple months ago and on an average day I'm going to have low AC load to drop, because I live in Oakland and the climate is moderate.

But on one of those hot days when the system is stressed, you know, I have load that I can drop. And I don't think, you know, the new baseline methodology that the ISO is talking about with the control groups, I think will capture that on the performance side. But in terms of capacity crediting, I think you've really got something of a dilemma because, you know, on an average day, you know, a thousand customers like me won't be able to give you much load drop. But on those days when you really need it, you could have a resource there

that's meaningful.

But if your capacity counting method is based on what's available under average conditions, you know, we're not going to get any credit for that resource because it's -- you know, if I were bidding into the market, I wouldn't have any load to bid to drop most of the time, but I would when it was most needed.

So, I'm not sure that, you know, ELCC or any of the other methods that we've talked about really captures that temperature sensitivity. And, you know, I don't have the right answer but I think it's something that really needs to be looked at more carefully is how do we -- how do we put a capacity value on loads that are only there on the hottest days of the year. Thank you.

MS. MURIMI: Thank you for your comment, Mike.

Once again, I'll just give an other quick call for comments. If you do have a comment, go ahead and use the raise hand feature. It looks like a high five at the bottom of your screen. And if you're on the phone line, go ahead and press *9 to indicate you'd like to make a comment.

Seeing no more hands raised, Vice Chair Gunda I'll hand the mic back to you.

CEC VICE CHAIR GUNDA: Thank you, Dorothy.

Thank you, Amaani Hamid, to Steve Uhler and Mike Florio for your comments. I think it's an important element of this public process is to, you know, hear broader kind of public comments and be able to take those into record and account as we move forward. And thanks for raising the questions, especially around the data accessibility. And then, you know, we'll continue to work on that.

And, you know, I want to thank Commissioner McAllister for his work at least to the extent that, you know, at the CEC the DIM data that's all going to come in. I just want to say that's an important issue for us.

You know, in closing, you know at least for me this morning's session was extremely helpful. Thanks again to all the speakers, Simon Baker, Anna McKenna, Jennifer, Paul Nelson, as well as Chetna Smith, you know, for your excellent comments as well as, you know, taking the time to provide answers to some of the questions that we're all trying to grapple with.

So, I just wanted to thank you all again. And thanks to all the attendees. You're the -- the public attendance and public comments really make the process, you know, helpful and bring together important lessons as we move forward.

I also want to just, you know, again the IEPR

team, but also Tom, Eric, and David Erne for their excellent work, and their persistence and commitment to ensure the working group process, you know, is played out as smoothly as possible, and allow for consensus building and trust building. I just want to thank them all.

I've kind of learned a lot and I'm looking forward to learning in the afternoon as well.

But before I close the session off, I want to see if Commissioner McAllister wants to add any comments.

CEC COMMISSIONER MCALLISTER: Well, thanks Vice Chair Gunda. Just you said most of what I would say and I just want to thank everyone again and, you know, not name names this time. But just really a great morning, lots of learning. And lots of different perspectives that are well grounded, right. So, that's kind of the essence of a rich topic is that there are lots of different ways to see it and how you see it depends on sort of where you're coming from. But everyone this morning was just deeply informed and, obviously, committed to getting answers that make sense for California. And so, I just want to thank everyone for that.

And also for the public comments, those were

very, very helpful. I think it highlights -- particularly Mike Florio's comment highlights just the kind of complication of aggregating, you know, lots of small resources at particular moments and what sort of program environment they best fit in. And so, I think, you know, I have increasing sort of optimism about the way to get those kind of peak resources harvested through rates, and sort of dynamic rates particularly on hot summer days. And I think we need to do better, as a couple of commenters said, a couple of the panelists said of defining how that happens, and being intentional and precise about that.

But looking forward to the working group discussion, delving into that this afternoon. So, thanks for everybody who will be -- who was on this morning and will be this afternoon. So, I'm looking forward to that at 2 p.m. Hope everyone can join us again, then.

CEC VICE CHAIR GUNDA: Thank you, Commissioner McAllister. I just want to see if we have any other Commissioners on the dais that would want to make a comment. I'm not seeing any, so with that thanks again for everybody for attending and participating this morning.

Please join us this afternoon as we continue the

discussion into the supply-side working group, and the different proposals, and the work that has been there.

So, we'll be starting that at about 2 p.m. and look forward to having you all join again and continue this conversation.

Thank you. With that, I would like to adjourn Session 1 of the workshop today.

(Thereupon, the Workshop was adjourned at 12:33 p.m.)

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I do hereby certify that the testimony in the foregoing hearing was taken at the time and place therein stated; that the testimony of said witnesses were reported by me, a certified electronic court reporter and a disinterested person, and was under my supervision thereafter transcribed into typewriting.

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