FEDERAL ENERGY REGULATORY COMMISSION

TECHNICAL CONFERENCE

DISTRIBUTED ENERGY RESOURCES

FEDERAL ENERGY REGULATORY COMMISSION

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WASHINGTON, DC 20426

Wednesday, April 11, 2018

9:00 a.m.

SPEAKER List

--Panel 4--

OEPI -- David Kathan, Michael Herbert, Ray Palmer

OER -- Joe Baumann (Moderator), Stephanie Schmidt, Alan Phung, Matthew Nutter, Monica Taba or Jomo Richardson

Larry Bekkedahl, Vice President, Transmission and Distribution, Portland General Electric

Donald Bielak, Manager, Reliability Engineers, PJM Interconnection, L.L.C.

Jens Boener, Principal Technical Leader, Transmission Operations and Planning Group, Electric Power Research Institute

Marcus Hawkins, Director, Member Services and Advocacy, organization of MISO States

Clyde Loutan, Principal, Renewable Energy Integration, California Independent System Operator

Jacob Tetlow, Vice President of Transmission and Distribution Operations, Arizona Public Servic3e

Ganesh Velummylum, Senior Manager, System Analysis, NERC

Tam Wagner, Senior Manager, Regulatory Affairs, Independent Electricity System Operator (Ontario)

--Panel 5--

Shay Bahramirad, Director of Distribution System Planning, Smart Grid and Innovation, Commonwealth Edison Company

Jens Boemer, Principal Technical Leader, Transmission

Operations and Planning Group, Electric Power Research Institute
Ning Kang, Staff Scientist, Argonne National Laboratory
Dennis Kramer, Sr. Director, Transmission Policy, Stakeholder Relations and Business Development, Ameren Services Company
Marija Prica, Assistant Professor, Case Western University
Binaya Shrestha, Regional Transmission Engineer, California Independent System Operator
Ganesh Velummylum, Senior Manager, System Analysis, NERC
Brant Werts, Lead Engineer, DER Technical Standards, Duke Energy Corporation
OEPI - Michael Herbert, Ray Palmer, David Kathan (possible)
OER - Stephanie Schmidt (Moderator), Alan Phung, Jomo Richardson, Gilbert Lowe, Sasan Jalali
OEMR - Laura Switzer
OGC - Mary Ellen Stefanou
--Panel 6--Afternoon session
David Crews, Senior Vice President, Power Supply, East Kentucky Power Cooperative
Mark Esguerra, Director, Integrated Grid Planning, Pacific Gas and Electric Company
Daniel Hall, Chairman, Missouri Public Service Commission and Vice-President, Organization of MISO States
Peter Langbein, Manager, Demand Response Operatoins, PJM

Interconnection, L.L.C.
Audrey Lee, Vice President, Energy Services, Sunrun, Inc.
David K. Owens, Retired Executive Vice President, Edison Electric Institute
Maria Robinson, Director of Wholesale Markets, Advanced Energy Economy
Jeff Taft, Chief Architect, Pacific Northwest National Laboratory
OEPI - David Kathan (Moderator), Michael Herbert, Ray Palmer
OER - Vincent Le, Stephanie Schmidt, Anuj Kapadia
OEMR - Lynn Massengill
OGC - Karin Herzfeld, Heidi Nielsen
--Panel 7 --
Joseph Ciabattoni, Manager, Markets Coordination, PJM Interconnection, L.L.C.
Matthew Glasser, Director, Consolidated Edison Company of New York
Gerald Gray, Program Manager, Information and Communication Technology, Electric Power Research Institute.
Ali Ipakchi, Executive Vice President,Smart Grid and Green Power, Open Access Technology International, Inc.
Lorenzo Kristov, Independent Consultant
Brandon Middaugh, Senior Program Manager for Distributed Energy, Microsoft
Doug Parker, Director, DSO Implementation, Integrated

Innovation and Modernization, Southern California Edison Company

Martin Ryan, Director, Real Time Operations, NRG Energy, Inc.

OEPI - David Kathan (Moderator), Michael Herbert, Ray Palmer

OER - Thanh Luong, Joe Baumann, Stephanie Schmidt

OEMR - Mark Byrd

OGC - Karin Herzfeld, Heidi Neisen

P R O C E E D I N G S

MR. BAUMANN: Good morning we'd like to invite everyone to please take a seat as we plan to get started here in the next minute or two, thank you very much.

Good morning everyone, my name is Joe Baumann and I'm with the Office of Electric Reliability here at FERC. We'd like to thank everyone for joining us for Day 2 of our 2-day Technical Conference on Distributed Energy Resources.

So far we have found this Conference informative, interesting and we hope and we expect to see that continue here on day 2. A couple logistic remarks before we get started. Please no food or drinks other than bottled water in the Commission meeting room.

There are bathrooms and water fountains behind the elevator banks on each end of the building. Please turn off your mobile devices or put them in the airplane mode while in the Commission meeting room to avoid interference with the audio visual and the sound equipment.

We have arranged for spillover space in Hearing Rooms 1 and 2. Today we have four panels. We will break for lunch approximately 12:10 p.m. until 1:30 p.m. For panelists today if you would like to be recognized to speak, please put up your name card, be sure to turn on your microphone and speak directly into to so that the audience and those listening to the webcast can hear you.

This Technical Conference is being transcribed so please say your name when you start to speak. When you are not speaking please turn your microphone off to minimize background noise. Panel discussions will not include opening remarks but will consist of a discussion based on the questions posed by Commission staff in the notice.

We'd also like to remind everyone that we intent to focus this Conference on the technical and operational issues described in the notice. We will not discuss other related matters including those at issue in any pending proceedings.

A quick note about Panels 4 and Panel 5 -- those are the first two panels this morning before we break for lunch. These panels are intended to discuss DER's in general whether or not they participate in the wholesale markets. Further, these two panels are in reference to Docket No. AD18-10-000.

After lunch Panels 6 and 7 will go back into market participation of DER aggregations specifically addressing coordination issues.

Panel 4 includes a discussion on the collection and availability of data on DER installations. It will also address the impacts to both power system reliability that results from increasing penetration of distributed energy resources.

I'd also like to highlight the reason we revised IEEE15-47 Standard -- we encourage the panelists to refer to the standard in their responses where appropriate. With that I would like to introduce our panelists and I want to thank them for joining us today. Many of these panelists come from the west coast so apologies for putting you on the earliest panel we had at this Conference.

We have Larry Bekkedahl, Vice President, Transmission and Distribution from Portland General Electric; Donald Bielak, Manager, Reliability Engineering, PJM; Jens Boemer, Principal Technical Leader, Transmission Operations and Planning Group, Electric Power Research Institute; Marcus Hawkins, Director, Member Services and Advocacy, Organization of MISO States; Clyde Loutan, Principal, Renewable Energy Integration, California Independent System Operator; Jacob Tetlow, Vice President of Transmission and Distribution Operations, Arizona Public Service; Ganesh Velummylum, Senior Manager, System Analysis, NERC and Tam Wagner, Senior Manager, Regulatory Affairs, Independent Electric System Operator.

With that we'll begin with the questions. Question 1 -- what types of information and data do bulk power system planners and operators need regarding DER installations within their footprint to reliably plan and operate the bulk power system? We'll begin with Jacob?

MR. TETLOW: Yes, my name is Jacob Tetlow, I appreciate the opportunity to be here and I think it's a great topic as we collectively work to transform our energy industry. As far as APS is concerned, and the focus on DER's and the type of information we need -- I should probably give you a little context.

We're a 1.2 million customer utility with about a 7% residential penetration rate so we've about 80,000 residential customers today with solar panels, rooftop. The focus for us is around the size, the location and the type of DER.

And we actually do production meter -- all 80,000 of those residential systems so they're mapped into our network and they're used for the actual solar production is used in that modeling of the network for load forecasting and planning of both distribution and spillover into transmission planning.

As a vertically integrated utility, much to the conversation yesterday, you know, we don't have any of the problems or challenges, our two control centers are about 50 feet apart so that makes it a little easier to flow information.

Some of the information we don't have would be more around like inverter settings and some of those ancillary details that you get further and further as you get into the distributed energy resources.

Our -- to give a little bit of context on the value of some of that as you get -- what we've learned is there used to be kind of a methodology there that hey, 30% penetration creates problems and some of those were kind of arbitrary numbers out there.

And having those real details has really helped us to understand -- there's times where you can be 50% penetrated on a feeder and not have any operational problems. You can equally be 30% penetrated and have operational problems as it relates to voltage management exceptions and maintaining your IEEE standards.

And the difference generally gets into the topography of where that is -- if it's a long feeder, high concentration of solar at the end of that feeder -- that will create many more problems than if you have a short feeder close to the substation with the concentration of solar near the substation.

So having that data and that would be my -- my greatest ask to FERC is, you know, helping get the data to the utility so we can accurately model and manage our systems -- I would say you can't manage what you don't measure and so measuring the DER's is critical to the success of it.

MR. BAUMANN: Thank you Mr. Tetlow, Mr.

Velummylum?

MR. VELUMMYLUM: Thank you Joe, I appreciate the opportunity to be here, thank you Commissioners. We had a lot of discussion yesterday about technology. It's obvious that this device can provide -- we all know these are smart devices -- there are a lot of capabilities we are trying to get to.

So I'm going to separate two things here -- one I'm going to talk about status data operation and I'm going to get into transient and sub-transient operation. We talk about LNP's and I know it's not my jurisdiction to get into markets but when we talk about megawatt, we're talking about steady state operation.

What do we see in the system, you know, under the steady state operation condition? For that purpose aggregating the information would be great. I mean it's good, sufficient. But you have got to understand when an operator system somethings thing happen -- a unit trips, you know.

So when you get into transient area we are in a different, you know, time domain here. And we know these devices are smart devices. They can provide more effective control, frequence in response, volt support, volt flux support.

So in order to be able to tap into that aspect of these devices we need to detail modeling. And I highly recommend that you know, we pay attention also to the details of this model when we talk about transient. And the biggest thing we have to keep in mind things happen right?

But we all have to remember how quickly we can bring a system back into a steady state operation and that's where these devices can help us to some extent but you have to model that, you need the detailed models -- that is my perspective, thank you.

MR. BAUMANN: Thank you Mr. Velummylum, Mr. Bekkedahl?

MR. BEKKEDAHL: Good morning Larry Bekkedahl, Portland General Electric and thank you for the opportunity. I appreciate you bring us all together here and jumping on a subject that is near and dear to a lot of our hearts 00 those of us on the operating side.

I'm going to chime in a little bit with Jacob, our utilities are in many ways fairly similar in that we're vertically integrated. We're about 900,000 customers, both of us are participating in the energy and balance market and so we look at things in very similar ways on the West Coast.

But things that I would mention in addition as we think about information and data that's necessary is Elon Musk said a few years ago that in distribution of the future we're going to have about a third of our generation in the distribution system. That's a change -- that's a big change for us and when you think about for us 4100 megawatts is what our peak is -- it's not a summer peak, it's not a winter peak and to put that in perspective, 1500 megawatts of generation into the distribution system.

Secondly, I would say that the worst thing that can happen for distribution companies is to not have visibility on what is that distributed energy resource. We operate -- right now our generation -- backup generation for a number of our customers, it makes up all of our contingency reserves that we're required across our system. We actually don't own it but we operate it, we maintain it and it's there available for our balancing authority at all times.

That's been a great resource for us for the last 15 years and as we think about the future of storage being one of those distributed energy resources, that becomes a spinning reserve for us -- how we can apply it. But we need to know where it is, the size of it and how it's being operated in a real time basis. And I think that's the difference as we go into the future.

The worst case is we don't have any visibility. If we don't know what it is, where it is, it will be much like we do with our load today -- we forecast. If we look at the loader feeder, we forecast and then we build to the worst case scenario.

We put in as much capacity as necessary and we have to say to ourselves is that the most we can do, is that optimizing the system? And if we put in more variable load which this would be, both on generation and we'll call it demand response being flexible load, if we don't see that we're going to build to the worst case scenario.

So we're not going to optimize, it's not going to be as affordable, it's going to be a very expensive option. And worse than that would be if somebody is operating it and you don't know about it.

So if we have an aggregator that is operating it and putting it into a market and you as a distribution operator don't see it, don't understand it, you've created a problem for yourself.

So I challenge us to think about that and I would say that the greatest benefits for both the system and societal is to think about how we optimize the distribution system. We have non-wired solutions. If we don't have to re-conduct, if we don't have to put a second transformer in, we start to utilize all the distributed energy resources and optimize it on the grid -- that becomes for both the system and society our greatest opportunity.

So with that it is information we can aggregate it and share it at the bulk system, but we'd like to see that we make sure it's visible at the distribution level.

MR. BAUMANN: Thank you Mr. Bielak?

MR. BIELAK: Good morning, Donny Bielak, PJM. I'd like to give this a little bit of perspective from the RTO/ISO standpoint. I'd like to echo a lot of the same comments that were just made but this is also from a standpoint of say wholesale versus non-wholesale DER, being such that if a DER were to participate in say the PJM market, it would be subjected to market rules and data submission requirements and we believe from an operational standpoint we would be able to work with our markets and our stakeholders to determine what would be best for them to adhere to.

So taking this from a standpoint of non-wholesale DER we're actually a bit afraid of DER resources installing and saying, "We don't participate in your market, why do we need to give you any information?"

And so, again, to echo a lot of these same points, as the reliability coordinator and the transmission operator, we like to take the standpoint from reliability data -- we'd rather have all the data all the time -- of course that's not feasible.

And we'd like to at least come up with something that would be say -- what's going to have an effect on our system, on the bulk electric system.

You could probably write that down. Again, to a lot of the same points that were already made, installation megawatt values, location, fuel type, if it's -- we know it's not going to be -- we know it's not wholesale it's not going to be telemeter, it's not going to be sent to us but at least if we have that type of information we can work it in to our forecast models and operate around it.

And I would actually break this down even into like a say -- what's going to be your, like a threshold, for what we would need to know. What's going to start having an effect on the bulk electric system? If you're a small rooftop solar -- it's not going to really even show up on to our system. But some of these DER installations are quite large -- talking 10-20 megawatts and they're not participating in the market so they don't have to adhere to our data submission rules.

But they can certainly have an effect, especially dependent on where they are located electrically. So if you're connected to say -- a 69 KV system which has a low rating, 50 NVA or so, just a 10 megawatt installation can have a very large effect.

So and some of our underlying 69 KV is needed for electrical liability and bulk electric system just because of how the electrical system is designed. So with that in mind, again, I would like to agree with some of the comments that were said even at a higher level, the RTO and ISO level, thank you.

MR. BAUMANN: Thanks, Miss Wagner?

MS. WAGNER: Thank you and thank you for the opportunity to participate on this panel this morning. So for a bit of context we are the system operator for the provinces of Ontario in Canada. We've got an installed capacity of approximately 40,000 megawatts of which 20% of that is variable generation.

Of that variable generation approximately half of that is actually embedded in our distribution system so we do have to face some of the similar challenges that you do in the states around the visibility of embedded resources.

I would like to echo a lot of the comments that my fellow panel members have already stated and really with the ISO we are -- we are supportive of enhanced visibility as well as increased dynamic data from a bought system perspective.

I can actually talk to the importance of modeling and I'd like to echo that and also reiterate the real time data needs as well. And while with the unique position that Ontario is in is that we are the transmission operator, we're also the balancing authority and we interact with over 60 local distribution companies in Ontario.

And while we are going through our LOTC

consolidation, just the sheer volume of distribution utilities in Ontario is a challenge for us. What we are doing in order to enhance the visibility from the grid level of these distributed assets is we do have a number of initiatives under way with our local distribution companies to implement -- develop and implement data sharing frameworks -- so looking at both from a static data perspective so nameplate capacity, generation fuel type as far as delivery points -- but also looking at it from a real time data perspective as to what energy injections there are into the grid and at what delivery point as well.

One of our key initiatives right now is around an LDC grid interoperability standing committee with -- where a number of our stakeholders and distribution utilities are involved and with that we're looking at how do we enhance the -- enhance and enable DER penetration within the Ontario system, but also around that integration piece and looking at what real time data can also be provided.

And I think my last point is it's really around the importance around the interaction between the LDC, the local distribution company and the system operator as well and what the dynamic of the distributed energy resources amongst the broader generation mix of the generation fleet so there is a point that was made around topology.

It's also a matter of how that distributing energies resources -- their behaviors and their physical operating characteristics also complement or not complement the generation supply on the bulk level as well.

MR. BAUMANN: Thank you, Mr. Loutan?

MR. LOUTAN: Our answer is 50,000 megawatt system is a big system. We can see the load shift anywhere from over 17,000 megawatts off-peak to about 15,000 megawatts during peak hours. Currently we have about 10,000 megawatts of transmission connected solar.

We have 6,000 megawatts of wind and we have roughly 7,000 megawatts of rooftop PV. So we are starting to see some unique operator challenges, you know, with that amount of variable resources -- especially when the loads go up.

Now, the type of data that system planners need is a lot difference from what system operators need. System planners they look for things like location, capacity, capability of these results so that they can do a composite load model to study the system looking at, from a stability standpoint.

From an operational standpoint, we look for 7 types of information transmission distribution interface. We look for things like voltage flows, direction of current flows, that load forecast, day ahead timeframe is something that we need and also in the real time timeframe, actual real time telemetry.

I guess everybody here mentioned the need for that and real time telemetry. So just think about on some days we operate the grid or about 25% of the load is being served by rooftop PV that we have no visibility of.

So one of the challenges for system operators as a system operator -- one of the responsibilities is to support the interconnection frequency -- supporting the interconnection frequency with 25% of the supply that you have no visibility of is really a challenge.

So, before DER how it is you know we did this. Well we got information in real time every 4 seconds from transmission connected resources. We also got information every 4 seconds from the interties so we could calculate load every 4 seconds.

And load back 5 years ago was pretty much predictable. Now in California the load is pretty much all predictable. We've got things like fresh response efficiency, the model response, plug in electric vehicles and the bigger now is DER.

So currently as I said we have almost 7,000 megawatts of DER, that is expected to increase to about 12,000 by 2022 timeframe. So the ability and uncertainty is expected to increase.

What we started to see is huge drops during sunrise, during sunset. And we recently calculated the contribution -- the rooftop PV has a ramp especially, we think it's anywhere from 3,000 megawatts to 5,000 megawatts -- that's a lot of ramping capability especially when you have no visibility.

So essentially today we have system operators trying to control a grid with an unpredictable demand with variable supply. So we always, you know, reactive mode. So we need to get that telemetry in real time, the TNE interfaces and in some cases we may have to get that telemetry beyond the TNE interface depending on the network topology.

Again, in order to help the system operator be aware of what he's facing in real time, telemetry is important and also some level of controllability. When I say some level of controllability of DER resources -- I mean not just being able to shut these things off and bring them online, we need to have some type of ramp rate controls.

For instance if they wanted to parse the market let's say -- we issue a dispatch instruction to allow the DER to go from 10 megawatts to 20 megawatts or vice-versa. We'd like that to happen across, you know, a certain timeframe or like a 2 megawatt a minute across 5 minutes.

So with that I'll stop too.

MR. BAUMANN: Thank you, Mr. Hawkins?

MR. HAWKINS: Thank you Marcus Hawkins with OMS. I will not be able to dive into the numbers like California that DER has reached in MISO and part of that is just the lower penetration of DER in the MISO footprint.

But another part of that is that in California there's a single state ISO where coordination with the CPUC and other parties allows for that data to be readily available to the ISO. But in the MISO footprint, the states really have visibility into more of that data and there's a 15 state footprint in MISO and so given that low penetration today, the states have recognized the potential impacts in the future and the need to start to have discussions with MISO on what type of data they would need at least from a planning perspective at the very least to conduct economic transmission planning into the future.

And so we've started those conversations and started to get an assessment of the type of data that's out there and how it's currently being used, how forecast of DER being used in the different jurisdictions within the footprint and then jumping on to what Donald was saying about the wholesale market participation.

Right now what wholesale market participation will look like within MISO is unclear and it might be impacted by varying state policies throughout the footprint so we're really focused in on getting a sense of what information exchange between the utilities and MISO might need to look like a baseline amount of information exchange for transmission planning and what that information consists of regardless of participation at either retail or wholesale.

MR. BOEMER: Good morning my name is Jens Boemer, I'm with the Electric Power Research Institute which is a not-for profit institution dedicated to the public benefit. My responses will focus primarily on DER data for building transmission planning cases for load flow and dynamic stability studies.

In the fundamental cycle timeframe as our underlying equity research has matured significantly in that area over the last couple of years. Many of my statements will echo what we have just heard from the fellow panelists and our research does suggest that DER needs to be included in dynamic stability and study state studies once DER reaches significant penetrations in the overall system.

And what really counts is the aggregate number of the DER on the regional basis on an interconnection basis. We also expect that leading practices for the assignment of abnormal performance categories which are defined by IEEE and Act 1547 which was published last week may include sophisticated modeling of DER in dynamic stability studies.

From an operations perspective, DER as we have heard, is expected to be less controllable and to a certain extent less available than conventional generation and as such more information will be needed to consider and to account for the changing availability of DER capabilities to reliably provide certain responses over time.

Note that as EPRY performs some research on bulk system operations with DER and related data need including balancing and frequency control. And to date, however, the results from that type of research are still limited and the answers to additional questions may be provided on request.

The DER transmission planning data which has been specified in the NERC reliability guidelines for DER modeling in our view, that's specified the minimum data requirements that will be needed to model the power system in a reliable and expert way.

This DER specified data is consistent with recent EPRY research that has been published and we recommend that to the greatest extent possible, netting of DER with load should be avoided. Note that the DER data is not only needed for the existing DER's in the system but we will also need that data for future DER's connecting to the system over the planning horizon.

There may be multiple ways for transmission planners to obtain that data -- each way allowing to represent DER performance with different accuracy and different transmission planning studies. And the uncertainties resulting from inaccurate DER data will have to be addressed in operational practices including reserve planning and security constraint, economic dispatch.

Certainly inaccuracies decrease as newer one gets to the real time operations.

MR. BAUMANN: Thank you, before I turn it over to Mr. Bielak, I just wanted to ask a follow-up question for our panelists to start thinking about. We've heard a lot about the different types of data needs here so as a follow-up are there procedures and agreements that exist in your footprint that exist to share this data with bulk power system operators and planners? Also, several panelists mentioned the importance of real time data. In your experience, in your footprint how do you balance the need for transmission operators to have access to this data while also considering the costs of providing this data to the bulk power system? With that I'll turn it over to Mr. Bielak.

MR. BIELAK: Thank you, Donny Bielak, PJM. I would really like to build upon Clyde's comment about the California ISA load and he said that the load is unpredictable. California ISO has a much larger penetration of DER than PJM so we look to them kind of in advance for shadowing as we build up our penetration levels closer to theirs.

And that's a scary thought -- load being unpredictable. We have very much -- we need an absolutely accurate load forecast in order to bulk operate the system and also operate it economically so if they're having patterns that cannot be properly forecasted, in order to maintain reliability you're going to have to start procuring additional ancillary services which comes at a cost so additional reserves, regulation in order to keep all the system operating limits and frequency at acceptable limits, thank you.

MR. BAUMANN: Thank you Mr. Bekkedahl? MR. BEKKEDAHL: So a couple of things as you're mentioning about the information sharing between and so for us I had mentioned the distributed stand-by generation that we have that actually is on the distribution so imagine if you will that the balancing authority wants to use that generation as an emergency on system, et cetera.

You need to quickly know is it available first -- are the feeders that make the path back into the sub-station and to the transmission grid there and available as well. So again, making sure that that visibility -- that that distributed energy resource you're going to call upon has all of the capabilities to do what you're asking it to do and to be able to trigger it and then verify that it actually happens.

Those are all critical pieces if you want to remain inter-reliability and to have the system actually function and do exactly what you're looking for. So many times our folks, even though we have that on the automated side, there's still phone calls that go on and people double-checking to make sure that things are there and available, so it is very complex on that behalf.

We're learning and again the better the data, the better the information that's flowing, we make better decisions on that.

MR. BAUMANN: Thank you, Mr. Hawkins? MR. HAWKINS: Thank you, Marcus Hawkins with OMS. To your follow-up question about the processes and procedures in place to share the information -- in the MISO footprint it's over 90% vertically integrated so the ability to share data within those vertically integrated utilities exist, but as far as procedures to share data with MISO, there's a pretty easy answer that process is not in place. There haven't been agreements or any sort of structure set up to share that data as off yet.

We're just starting to think about what that might look like today, so.

MR. BAUMANN: Thank you Mr. Tetlow?

MR. TELOW: Thank you I was just going to add to your follow-up question. As a vertically integrated utility the ability to share data is fairly easy but as we have seen the penetration of DER's over the last, you know 10 years -- 10 years ago we had 200 systems, today we have 80,000.

As we progress down that road, the importance of building that into your distribution planning came up very early in the process to assess each of your feeders. When you have 1300 distribution feeders, that data today has a very defined process as it relates to the reliability of the thermal overloads, the hosting capacity if you will for additional DER's -- that all gets done on that distribution side but there's a very formalized process that you transmit at a feeder level to your transmission planners for system operating limits and other criteria like that.

There is a cost for that data, you know, if you want that data accurately -- it's not real time today when we put a production meter on a solar array -- it's about an hour delay, but it does come with some cost and then in our opinion that makes a lot of sense for truly understanding what all the inputs are to your system from a network modeling perspective and operating perspective.

MR. BAUMANN: Thank you, Mr. Velmmylum?

MR. VELMMYLUM: Thank you Joe. I -- I think we need to start with the transmission owners. We have standards in place like for so many interconnection standards that talk about end user customer. I think it's very important and imperative that transmission owners be very cognizant about the data.

So any interconnection agreement with a customer they need to specify dynamic data, steady state data they need. It starts with the transmission owner. They have to make sure before they interconnect a request that these data are provided.

So that once we have the data, then we can transfer the data to the transmission planning and planning coordinator to the standards so the facility and the connection standard talks about end user customer, the data they need. And once we have the data we can do studies and we share with the adjacent planning coordinators.

And they have to comment and respond within a specified timeframe that they agree with the study that's been done that's noted by the impact. So we have to start collecting the data to the transmission owner interconnection process when this anticipated energy results interconnect into the system because that's the jurisdiction that they have, thank you.

MR. BAUMANN: Miss Wagner?

MS. WAGNER: So in Ontario most of our -- like I indicated, we've got approximately 4,000 megawatts of embedded generation. For the most part these embedded resources were contracted through feed-in tariffs, and the ISO is actually the counterparty to those contracts.

So from a static data perspective we do have access to, like I had indicated, plate capacity -- standard 2 field type as well as delivered point. However, in Ontario we have I guess that time of feed-in tariffs has concluded and so we aren't procuring embedded resources in that respect anymore.

We're looking similar to many folks here are looking to integrate that into our wholesale electricity market and so we realize that from a data perspective is we've got to take another approach and how do we get access to that data?

From a dynamic data perspective, a number of years ago the -- as we were starting to see the increase in penetration of renewable generation, DISO undertook a renewables integration initiative. Part of that was to look at visibility, forecasting and control of these -- of these resources.

The outcome of that initiative was we now implement centralized forecasting for renewable energy generation, this includes the embedded generation as well as dispatchability of these facilities. And in order to be successful in that we do have, I guess, minimum DEO requirements associated with that.

What that applies to is for the embedded generation -- any renewable embedded generation that's 5 megawatts or greater, there are telemetry requirements -- real time telemetry requirements that they need to provide to the ISO, whereas with some of the traditional natural gas -- embedded natural gas generators that threshold is set at 10 megawatts.

But even with those increased enhanced data requirements we are still -- that only represents a fraction of the embedded generation within Ontario so we do acknowledge that there is more work that needs to be done.

From a -- when we look at some of the distributed generation that's uncaptured within our market rules, our provincial energy regulator -- the Ontario Energy Board, does have requirements for the local distribution companies who are all regulated by the provincial regulator to meter there and better generation -- so that data is available to the ISO.

The only challenge is that's available on a historical basis so it isn't real time. So that is something that through the initiatives that I talked to before, around that increased coordination between the ISO and our local distribution companies, we're looking at what those other potential data-sharing agreements are.

And to your follow-up question around that balance between the reliability need for the data as well as the trade-off with the economics. And I think that boils down to really the relationship between the system operator and the local distribution utility so to the extent I know in yesterday's discussions the topic of this distribution system operators came up and to the extent that with that sort of relationship or that dynamic, some of that control is not necessarily at the bulk level but at the DSO level is potentially that aggregated data is sufficient and so you don't need to necessarily impose as stringent data requirements.

But in Ontario that type of future hasn't been determined yet so when we looked at potentially the system operator interacting with 60 plus distribution companies we do see the need for potentially more granular data requirements but at the same time we don't want to impose a barrier to the integration of distributed energy resources from an economics perspective.

MR. BAUMANN: Thank you, Mr. Loutan?

MR. LOUTAN: So we pretty much from a planning perspective know the amount of DER, where it's located, the capacity, the technology. Every year we send surveys out to all the load serving entities in California within the ISO's jurisdiction and we collect that data. We develop profiles, you know. Profiles in the sense of we try to develop minute by minute profiles for rooftop PV to determine the impact it has on system operations.

We also do forecasts -- day ahead forecasts but we have a third-party provider that provides us with this forecast. We do make adjustments to the load. Just for clarification, when I said the load is pretty much all predictable today -- when you think about 5 years ago a load was pretty much temperature dependent. You know what the temperature is, you know what the load is. But with all the variations and things like you know, as I said in my response, electric vehicles -- everything else that's on the system it makes it a little more difficult.

So whereas 5 years ago we know our trajectory with where the load was heading, no you have a range which makes it a little challenging for the operators. So even though we know from our planning perspective what we have in terms of DER, our rooftop PV, from a real time perspective we have no telemetry and this is what makes it difficult.

So as I said, you know, the operators they are always reacting to the system changes.

MR. BAUMANN: Thank you, Mr. Boemer?

MR. BOEMER: Jens Boemer with EPRI. I would like to shift the attention on what are the low-hanging fruits and what are the really important data aspects that we can start harvesting as soon as possible.

And you know, one of the lessons that we learned in my home country over in Germany is that if you can collect data relatively easily, it's very wise to do so as soon as possible because if you don't collect the data, it costs you more to start collecting it later on.

And if you don't collect the data, you do not see what's coming and you want to see what's coming especially when you plan a power system. So we heard a lot about planning data and operational data. It seems as if processes could be put in place that start collecting data for transmission planning including DER impacts with less effort than making available real time data from DER's.

And if that was the case it would make sense to start focusing on the data that is really important for the planning and that certainly includes DER aggregate capacities under given sub-stations. It includes the types of DER that are connected there and if we look at the stability and reliability of the balance system that we planned several years into the future there seems to be one critical data aspect that should need our attention and that is the potential wide area tripping of DER based on frequency and voltage disturbances.

I just want to mention one example that we addressed over in Germany a couple of years ago and that was the so-called 50.2 hertz problem which was a risk analysis for hundreds of thousands of DER's connected to the distribution system in Germany and it became clear that those DER's were programmed to trip at frequency thresholds that are very close to normal frequency.

None of the German transmission operators had modeled that problem in their studies but just by, you know, reviewing literature, understanding how interconnection standards work, one was able to identify that there's a prevalent risk. Unfortunately it never occurred that any of these large scale trips happened when a lot of DER were feeding into the system, but it was regarded as such an importance that the German government set up a retrofit program to reprogram the frequency trip settings for more than 400,000 installations of distributed PV.

And I think it becomes clear that things like that we'd rather want to see ahead of time and don't want to have to consider when these DER's are already connected to the system and I believe that collection of DER data as soon as possible for planning purposes can help us address some of these potential issues that we may have with increasing the integration.

MR. BAUMANN: Thank you, Mr. Bielak?

MR. BIELAK: Thank you, Donny Bielak, PJM. Thank you Jens, that was very insightful. From a data collection standpoint PJM currently leads a voluntary data collection effort. The -- it is voluntary so it's not -- it's not 100% exact.

We can use that to develop some general profiles as far as how that's going to off-set load, maybe regionally. However, it doesn't give us enough granular data for localized transmission impacts. And that's why we would need the aforementioned data requirements in order to gather that data to have the visibility.

I can indulge you in a quick example. I watched a lot of Law and Order -- do I have to submit this to evidence. The -- in a particular area off of a 115 KV loop during outage and post-contingency conditions it was studied reliably by both PJM and the TO that the outages were reliable through peak conditions through traditional modeling methods.

It turns out unbeknownst to either us or the transmission owner there was an aggregate of about 80 megawatts of behind the meter solar off of a -- well actually of about three feeders. However, post-contingency they were all going to be fed radially from the same 115 KV line.

So when we went through the typical summer peak load about 1700, no issues observed on the bulk electric system. However, once we got to about 2000 and the sun started to set that load started to dramatically increase and really caught off-guard the PJM operators, the transmission owner operators and they had to take reactive actions to mitigate the overloads that were not caught in any type of day ahead reliability studies or day of reliability studies.

And moving forward, if we've already seen it once, with a low level of penetration that we have now we can only expect to see it more often and more prevalent moving forward and from a reliability standpoint we will do whatever we have to do to maintain the system operating limits as the RC and the TOP.

And I hate to throw this out there but that could be up to and including load shed. So without this type of data we could be looking at, you know, drastic emergency procedures to maintain reliability on the bulk electric system, thank you.

MR. BAUMANN: Thank you Mr. Hawkins?

MR. HAWKINS: Thank you Marcus Hawkins, with OMS. I just wanted to quickly agree with some of the things I heard from Jens and Tam about the availability of operational and real time data.

In the MISO footprint, there's a varying ability to even get that insight into real time operations and a lot of it is determined by different state regulator decisions on investments into various grid modernization, initiatives and things like that.

So it would not be uniform throughout the MISO region and therefore like Jens said, it might not be an easy next step to take. And so we would encourage FERC to avoid creating burdensome requirements and allow for some of that flexibility for states to pursue their own policies in that area and not require some expensive technology to gain that insight when it may not be needed.

MR. BAUMANN: Thank you, Mr. Bekkedahl?

MR. BEKKEDAHL: Yes, Larry Bekkedahl, Portland General Electric. I really appreciate Donald's example and relating it to transmission slash in the sub-grid arena. But if you move down to that distribution side where we have to maintain an ANCI standard plus or minus 5% on 120 volt basis and you could see these fluctuations happen very quickly and you put yourself in those customers homes where voltage is swinging one way or the other -- we don't have equipment there that's protecting them.

You know damage to refrigerators and other devices in the home you have to start to think about. So that's created a curocality, of what we're talking about when we start to say variable generation on and off, who sees it, how do they see it -- those are the types of impacts, serious impacts right on down to the homeowners.

So, it's a great example of what can happen if you don't have insight, if you don't see it and you're not able to control it.

MR. BAUMANN: Thank you, so we've heard from several panelists on the planning and operational impacts to the bulk power system reliability as DER penetrations increase. To follow-up on that we wanted to ask what potential reliability benefits or opportunities can DER's offer to the bulk power system and what, if any, actions need to be taken to unlock these benefits and opportunities, Mr. Velummylum?

MR. VELUMMYLUM: Thank you Joe. I think it was yesterday was it panel 3 Katie talked about we have to capitalize the benefits the DER can bring to the system. I'm going to give you an example of we focus so much on, you know, on megawatts right?

So I'm going to give an example of let's suppose you have a couple of DER's in a facility that could provide megawatt support under Clyde's situations -- my colleague here that you need to ramp up these, you know, due to the changing load.

Well we have so many resources and these are smart devices. They can do a lot of things. So we can have one inverter providing the megawatts support but then you have another question to ask just because you have the megawatts support can you transfer it -- is it transfer capability because you need voltage support to do that.

So then you can have another DER providing voltage support while the others provide megawatt support. So they work in tandem together so we have to look at it in whole -- what these devices can do at the same time and what kinds of benefits they can bring to a system.

So the technology is there but we have to capitalize how we want to operate a system for megawatt support, for volt support, for frequency support -- the technology is there, they can do a lot of things.

So we have to call them in so this is where visibility is important to the system operator. And he can plan the system such that you have so much mega resources for megawatt support and I can use so much for voltage support or frequency too.

So I think it's very imperative that we don't just focus on one problem here we have to look at it as, you know, because they all interact. The systems are interconnected. You can't isolate the system you know, unless it's a radial line.

I think it's important we look at the collective benefit that DER's can provide. But at the same time we have to be very careful. What if they're not there to provide the system help when we think they are there?

So we have to look at it from what aspects -- when they are there, when they are not there. And if they are there how much can we count and how do we fractionalize different benefits that we can reap from these devices -- so that's very important and I think we need to stress that point here, thank you.

MR. BAUMANN: Thank you Mr. Beckkedahl?

MR. BEKKEDAHL: Yes, Larry Bekkedahl, Portland General Electric. And I give the example of how a distributed energy resource really can help and benefit us. And we've had for some time now as we bring on renewables, all of a sudden what used to be fairly stable generation is now moving on us on the generation side.

It used to be load would, you know, move very slowly and we would move our generation to match that -- that's what balancing was all about. And now that we've got variable generation going on it's really nice to have variable load. So if we can flex load over here -- whether it's demand response or it's distributed energy resources, and help us to balance in a better way we get higher reliability.

But to give you a real life story and share you know, prior to joining Portland General Electric I was with Bonneville. We were planning for a 500 KV line that needed to be built in the Portland area to maintain reliability because we had during the summer peak no generation from south of Portland. Obviously if Portland was hot, California was hotter -- there was going to be no generation.

Well today with all the distributed energy resources as a gentlemen from Cal ISO Clyde was mentioning, they have over 16,000 megawatts of solar now. During that solar summer peak now we see a generation coming our way and that in effect now was the cause for Bonneville to cancel a 1.2 billion dollar project to build a 500 KV line.

So can we do things in a different way? Can we find non-wire solutions by applying the technology -- absolutely. But I think you'll see those benefits as we go forward not only grid level, but especially in the distribution level.

MR. BOUMANN: Thank you, Mr. Tetlow?

MR. TETLOW: Jacob Tetlow with Arizona Public Service. I thought I would talk about a couple examples on operational impacts that I think are relevant. There's obviously -- there's wins and there's losses and anytime you deploy new technologies.

One of the -- a good example of a winning opportunity in Arizona we deployed an 8 megawatt battery, an 8 megawatt hour capacity battery that actually deferred a capital investment of a re-conductor of a 21 KV power line

-- pumpkin center -- 6 million dollar project and it's in service today -- a great example of using a DER to solve a non-wired traditional solution.

On the flip side of that we also see voltage impacts. As I mentioned before, you know, where the DER is on a given feeder will ultimately impact the reliability of the voltage and as Larry mentioned as well, voltage management is a challenge.

One of the operational impacts that came about to us in that space was it actually got to the point where we could see it even on the sub-transmission level at the 69 KV level. And it required us to change the way we study our system.

You know, traditionally, especially if you're in Arizona, large air conditioning loads, 7300 megawatt peak load, you really focus on that peak -- peak-load condition. And what we've learned to do is to study are system at peak renewables and at peak loads so it does require additional work to make sure you're evaluating your system at multiple different scenarios because it's not a dispatchable resource.

When you asked the question about actions to unlock I have two thoughts that come to mind there as far as allowing utilities to get the data -- to give us the data, to model the systems, to operate the systems with a focus on safety, reliability and efficiency.

And the better the data the better we will be able to capitalize on the efficiency. As far as it relates to the technology solutions, technology is moving so fast that my ask would be in Arizona Public Service is allow us the flexibility to deploy the right technologies. Don't get overly rigid on what solutions have to be provided.

Technology is moving very quickly and the solutions will vary by utility and by state and by region and by operating of the environment. So that flexibility will be important for figuring out what technology provides the best value to our customers.

MR. BAUMANN: Thank you, Mr. Loutan?

MR. LOUTAN: How can DER help? So one lesson we learned on transmission interconnected variable energy resources is to a degree of high levels of renewable resources on the grid, we found out that it was necessary for these variable energy resources to provide essential reliability services like voltage control, frequency control, off-ramping capability.

Now the same thing we started to see we will need -- as I said we already have days with 25% penetration of load being served by distribution resources. So we think one of my answer's going to be you know, DER's should also have the capability to provide essential reliability services.

By 2020 as they said we're going to have about 12,000 megawatts of behind the meter rooftop PV -- that's a huge part of your supply so pretty soon we're going to see 50% of that supply being from rooftop PV.

We don't have in the capability to provide essential reliability services. It's going to be difficult to control the grid, so, that's something we need to think about.

MR. BAUMANN: Thank you, Mr. Bielak?

MR. BIELAKE: Thank you Donny Bielak, PJM. I'm very intrigued by the non-wire solutions and the ability to do that. As it was mentioned before it was you know, how much can you count on this?

I'd like to point out that PJM has a market and provides market incentives for performance. So one of the key ways of locking this potential would be to encourage the market participation of the DER and then we could incent them further performance. We know that we can count on them reliably to off-set any type of loads and maybe defer any type of transmission upgrades that might be required.

And then we would also have the data we would need in order to -- in order to implement those solutions. So I think that's certainly an option that we can work with. If the -- if the generators or I'm sorry, the DER's are not going to participate in the market we would still like to try to use that data as much as possible but I think there's going to be a lot of studies and reliability analyses that would have to go into that and the only way that you are going to be able to do that to determine how much you can rely on the needed resources is through the proper amount of data, thank you.

MR. BAUMANN: Thank you, Mr. Boemer?

MR. BOEMER: Jens Boemer with EPRI. I would like to answer your question -- what are the steps to unlock the potential of contributing benefits from DER's to the bulk power system. And I would like to remind us that the very first step is to make sure that all these devices are having the capabilities of providing services.

We have heard from Ganesh from NERC and others on the panel that these devices are already smart devices now a days and that statement is -- can be backed up and supported by the fact that IEEE Standard 1547 has been published last week and some states have a few years ago already published interconnection standards and guidelines that require smart inverters or other smart DERS.

What's important to understand is that there's a difference between having the capability to provide these services which is required in interconnection requirements and actually providing the services.

So with these new interconnection standards we have laid the foundation for all of these devices that are going to connect under the jurisdictions where these new standards apply to be capable of providing the services.

That means that once these services become necessary for bulk power system operations, we have the ability to plug into that capability at the right time. It's important to recognize that this seems to be the state of the art right now and we do not expect any additional costs that DER vendors would require to -- to implement these capabilities compared to other devices on the market.

And one important aspect is also that the capabilities are three-fold. The first part of the capabilities relates to autonomous functions and these autonomous functions they do not rely on communication or remote control.

The second part is these new standards, especially IEEE Standard 1547 now requires the communication capability also from all DER's once it's adopted in a certain jurisdiction irrespective of the size of the type of the DER.

So that includes the small scale rooftop PV systems that would connect under the new standard. They need to be capable of communicating one out of three specified protocols. Well that said -- it's written on a different page when that capability would actually be utilized and especially with regard to communication capability one would have to roll out the communication infrastructure or telemetry to actually plug into that capability.

Once this communication infrastructure was in place these devices will be capable of not only sending information but also receiving information which then relates to the control from the real time operations, thank you.

MR. BAUMANN: Thank you, Miss Wagner?

MS. WAGNER: Thank you Tam Wagner from the IESO. So I would like to echo a number of the comments that we heard this morning as well as what we heard from Panel 3 around some of the benefits that DER's could provide.

So to the extent that they could provide a number of reliability services from a capacity energy and certainly services sub-frequency control in regulation and just to draw on a point that Donald from PJM indicated at the ISO as a reliability coordinator we will do whatever is necessary in order to maintain reliability.

`And DER's can be a part of that solution. They can be a part of what we've talked about in Ontario is they can be a tool in our reliability tool box and part of how to enable the successful integration of them is on the data requirements perspective.

And to Jacob's point around not prescribing solutions -- Ontario went through a period where we were prescribed solutions and prescribed targets for distributed energy resources and we are moving away from that and putting them more into -- integrating them more into our competitive market functions.

And in doing that we find that the DER's can provide that reliability service but also in a cost effective manner so it's really being able to balance the reliability aspect of it as well as the economics piece.

MR. BAUMANN: Thanks and I'll quickly go to Mr. Hawkins before we turn to our next question.

MR. HAWKINS: Thank you, Marcus Hawkins with OMS. Just one thing that didn't get mentioned about the non-wires alternatives solutions is where that consideration takes place in the traditional transmission planning process is a struggle and giving a DER solution -- kind of apples to apples comparison to the traditional wire solution has been a conversation within MISO of how much time is needed, is it an actual reliable solution and what type of agreements need to be in place, what visibility needs to be in place for that solution to truly mitigate the issue that has been identified.

And so that's an area that we've continued to struggle with in the MISO region.

MR. JACKSON: Good morning. How are long-term projections for DER penetration developed?

MR. LOUTAN: Clyde Loutan, California ISO. A couple of things -- one, it depends on the state's environmental policies. That drives DER installation. So to me like California loads -- as I said we survey the loads of different entities on a yearly basis to see what's coming in. We look at three years to see what's coming in within our controlled jurisdiction across three years so we can plan in terms of the operational challenges we expect to see -- and try to mitigate it out ahead of time.

One thing also we do to try to address that is we evaluate our performance on an hourly basis right? So, each hour we look to see did we help to support the interconnection frequency or not? So we use all of that data that we collect. We build profiles and then we look up and then we look back.

So looking back on every single day we look and see which hours it is -- we tell it to lean on the interconnection or we are able to meet the intra-hour ramps, the multi-hour ramps -- things like that.

We did see, you know, some challenges that decided to show up but I think if we looked at standards the way they were developed like for instance, NERC has four standards that we need to comply with in real time.

And if you look at those standards, you know, just on the surface, you would not see the potential rules. So we actually have to look for places where we would have challenges, so by looking at the system performance or how well we can support the interconnection frequency on an hourly basis, we can tell, you know or we can see impending problems ahead of time and try to solve those.

So by doing that we were able to go back to NERC, you know, specify here -- we have a ramping problem out west and now ramping capability is an essential reliability service to integrate high levels of renewables, so.

MR. BAUMANN: Mr. Bekkedahl?

MR. BEKKEDAHL: Larry Bekkedal, Portland General Electric. Mr. Jackson this is a tough question and it is one that I think we're all wrestling with but I think there's some indicators out there -- those states that are mandating certain programs, whether it be on storage, that drives obviously the direction you're going -- how many electric vehicles.

So in Oregon just saying we're going to put 50,000 vehicles in by the end of 2020 drives all of a sudden decisions of, you know, how you're going to move and you look towards mass transit -- are they going to do high or fast charging battery stations for buses you know for a 15 minute roll-out on a bus -- that means a megawatt of a battery sitting there to charge that bus as it goes by and how many stations do they want and how many buses?

I mean you're working to think about those things as they move forward. I commend you, you were recognizing in your technical study with EPRI working on the open BSS how to do the models for distributed resource planning -- how does that fold in to what we do for our IRP process -- that becomes critical for us when we're trying to think ahead as we see those and take advantage of it.

I will also say that it -- our AMI meters now we can start to think and look and examine customers as to what's base, what's variable loads, what are they doing in terms of demand response themselves.

So we're trying to understand at the customer level because if you can forecast at the customer level you can roll that up to the feeder level, you can roll that to the sub-station, you can roll it right up to a utility base.

So, again what used to be studied at the high level for a utility, you're trying to do it now in the micro level down at the customer base. And I guess my last comment is -- is how do we incent our customers? How are we incenting this to take place will drive a lot of these programs so whether it's legislated, whether it's pushed by a state Commission or actions that you take are going to drive much of what takes place in this space.

MR. BAUMANN: Thank you, Mr. Bielak?

MR. BIELAK: Thank you, Donny Bielak, PJM. Echoing a lot of Larry's comments here, so a lot of our long-term projections are going to be based off of the best data that we have available currently to us which can be rather scant.

I had already mentioned the voluntary program for data collection that PJM conducts -- so we use that to try to develop our longer term forecasts. But I'm sure you're all familiar with GIGO -- garbage in, garbage out.

So I mean if you're going to have better data up front, you're going to be able to have better models, better forecasting, more accuracy later on. For an example the behind the meter DER is inherently baked in to the meter load.

Now we come up with our load forecasts on a daily, hourly, minute by minute basis, and we noticed last summer our summer peaks just weren't quite materializing the way we would have traditionally expected them to.

Now we didn't have enough data to drive and point to anything in particular, but the working theory is that there were behind the meter installations that were off-setting load through the peak summer days -- probably rooftop solar off-setting our air-conditioning and -- but then that's a little reactive.

So we don't -- we didn't go into the operating day having an accurate load forecast. Our load forecast was slightly high and then we had to react to that as we got more data points because we're constantly revising our forecast models to expect that the loads in particular areas would be less.

So with this aforementioned data with it we can develop better forecasts in advance, not just long-term but also just for an operating day which is going to increase reliability, thank you.

MR. BAUMANN: Mr. Hawkins?

MR. HAWKINS: Thank you, Marcus Hawkins with OMS. In the MISO region there's also a voluntary survey that is used as part of a third-party consultant's effort to produce a long-term projection of DER in the footprint and that's intended use has been contemplated to be the transmission planning side of things and so being that it's voluntary in their most recent effort there was low participation on getting specific DER information back into that survey so they ended up using a lot of already publicly available data to produce their forecast and that included different things as technology adoption curves and economic projections and things like that.

But another part of that process was actual outreach to states and other -- other parties to get a sense of the policy drivers that are increasing adoption in different parts of the footprint so there's some good back and forth in that process on what might lead to adoption in the future.

And then also different states have different IRP processes that they require certain looks at DER penetration in the future.

MR. BAUMANN: Thank you Mr. Tetlow?

MR. TETLOW: Yes, Jacob Tetlow, Arizona Public Service. I think it's a great question, I think it's a big challenge for all of us to try to project what distributed energy is going to do. To answer the question directly we plan our distribution system on a five-year plan.

We plan our transmission on a 10-year forecast because of the time it takes to install the larger capital projects. So that inherently has some challenges as it relates to the drivers behind DER penetration, whether it's a market dynamic, a policy of either state or a federal level, the technology which is -- in and of itself very difficult to predict, and then how as a utility you try to shape your rate design to send the right price signals.

I think that's a big challenge for all of us and I would only suggest that the better we can add certainty to any of those variables, the better off we would be for the ability to predict the distribution impacts to DER's which then plays into our transmission finding decisions that are a much longer timeframe.

MR. BAUMANN: Thank you, Mr. Velummylum?

MR. VELUMMYLUM: Yes, thank you Joe. I just wanted to, you know, you talked about numbers right. And we have a reliability assessment group led by John Mauro, Tom Colliman, Nicole and Elliott, my colleague here, I'll give you some numbers when you ask about, you know, a lot of utilities that repeat that.

The 2017 LTRA report if you read the report talked about, you know, the penetration of DER across the North American footprint continued to grow and it's estimated of more than 26 gigawatt of non-utilities capability will be added to the network by 2027.

MR. BAUMANN: What's the total generation in North America -- does anybody know?

MR. VELUMMYLUM: I mean if you read the LTRA report you should know. 26 gigawatt right? You know what the North American generation is -- about 1200 gigawatt so do the math, 26 divided by 1200 -- that's what we're looking at.

This is in addition to, you know, by 2027 so the numbers are growing. So it's time, you know, we start taking this seriously. One thing these devices have that we should take advantage of and that's speed. These things can act very fast.

Speed is in our hands folks, let's take advantage of the system and technology, thank you.

MR. BAUMANN: Thank you I was told there would be no quizzes today, so Miss Wagner?

MS. WAGNER: So within Ontario with regards to how we do long-term projections for distributed energy resources -- like I had indicated is because most of our embedded generation has been procured through long-term contracts. The ISO has had the access to nameplate capacity and such.

So we do incorporate that into our long-term planning projects through energy system modeling and scaling it up to the contract capacity levels, but as I had indicated is there is a bit of a big paradigm shift in Ontario and to the extent that we aren't procuring those facilities through contracts anymore.

And I think similarly as to what John had indicated is we are seeing a lot more of this distributed energy resources being behind the meter so it does introduce a lot more uncertainty around our long-term planning for these resources.

We do also have to incorporate as some of my other panel members had indicated is what the energy policy is around electrification of vehicles so from a residential homeowner vehicle perspective but also from a broader electrification of public transit.

So we're finding that with I guess in 2016, we issued a long-term Ontario planning outlook, and we are finding that are projects were now not so much definitive but we were projecting more around the ranges in order to capture some of that uncertainty.

MR. BAUMANN: Thank you Mr. Boemer?

MR. BOEMER: Jens Boemer with EPRI. I think it's important to differentiate what the steps are to develop long-term DER adoption forecasts and I think it really starts with having a good understanding of the status quo -- meaning what are the DER connected to the system today?

And then once we know that one can go through scenario analysis and maybe stakeholder processes to get a better understanding of how many DER's will have connected in the planning horizon of 5 to 10 years.

With regard to that first step we see that the practices of collecting data for the status quo very-quite significantly among the regions -- those states that may have dedicated rebate programs may have public records available -- for example on a postal code resolution that could help understand what DER's are connected to the system today even without having the need to closely coordinate with distribution companies who may maintain that same data in more granular resolution.

Those states that do not have these public records available, they may be lucky having integrated utilities that have that data and can relatively or could relatively easily exchange that data among their distribution planning and transmission planning departments.

And we look forward to seeing to what extent distribution companies who often maintain DER data in their GIS, geographic information system, may leverage that type of data for distribution planning and once it's available they are also for transmission planning purposes.

Now with regard to the future, the development of the long-term projections there's a range of methods available that may range from simple scaling of existing installations in order to match future say statewide DER targets all the way to more sophisticated methods, either top down methods such as using resource potential models, for example EPRI's U.S. region model.

Or, even both market approaches where a customer's behavior would be considered in order to forecast DER adoption, especially residential adoption from the bottom up. All of those models and methods come with some uncertainties and therefore it seems important to include stakeholders in the discussion and in the verification of these numbers as early on as possible.

And since I referred to one example in Germany in a previous answer I'm going to refer to a similar example here in that context. In Germany the 10-year long-term grid planning scenarios are developed in a very open, very sophisticated stakeholder process and different scenarios with different policies are considered and although we will never be able to fully predict the future that gives us the best data available to make reasonable assumptions and also look into different cases and what the potential impacts on the bulk power system may be.

MS. TABA: Thank you, I just had a basic question. I've heard the concept of hosting capacity being mentioned by several utilities as a practice to determine how much DER's they can actually accommodate -- is this something that many utilities do, is this a common practice? Does this help at all with trying to forecast how much DER's you can integrate in your system?

MR. BAUMANN: We'll start with Mr. Tetlow?

MR. TETLOW: Yes, Jacob Tetlow, Arizona Public Service. To answer the question directly, yes we do hosting capacity as the Arizona Public Service. We watched as some of the California utilities led the way, I think, in some of that space but it was really about, you know, as a customer focused utility you want to enable your customers to do what they want to do and the quicker we can accommodate those requests -- well understanding what the impact would be to those request are helps you expedite that process and model your system.

So we have taken our high penetration theaters, about a quarter of our system, and that's been our initial starting point as, you know, so if you have 1300 distribution theaters we have about 250 of them today that we have focused on to identify what those system impacts are of the DER's such that we can accommodate in an expedited fashion additional DER's and understanding what the constraints will be operationally as you accommodate the additional DER's.

MR. BAUMANN: Thank you, Mr. Bekkedahl?

MR. BEKKEDAHL: Larry Bekkedahl, Portland General Electric. So just to follow on to Jacob's a little bit is that we -- yes, many of us have been using and EPRI was leading, thanks to Mr. Boemer here leading that charge to help us all to develop what those studies look like and as Jacob mentioned earlier we used to do 5 year studies.

Now you've got to understand what's that feeder going to do on a daily/hourly basis to be able to make a better forecast. You can't rely on that worst case scenario. You need to understand and again the netting affect, the masking of as you think about how that's deployed, so there's a lot more involved in being able to do that today.

But the majority of the utilities are now moving into that space.

MR. BAUMANN: Thank you and Mr. Boemer?

MR. BOEMER: I just want to clarify what we understand by hosting capacity since it may not be clear to everyone. So hosting capacity is a method that uses sophisticated distribution grid data and information on a potential DER interconnecting to a given distribution feeder and then run quasi stationary load flow, time theory simulations and also to a certain extent study state short-circuit simulations in order to develop a better understanding of the thermal impacts on the distribution system and the voltage profiles and potential distribution protection impacts from DER's.

And after all this information is highly aggregated and visualized in what we call heat maps that can indicate how much DER may be able to interconnect to certain areas of the distribution system.

MR. HERBERT: Alright thanks guys. This question largely focuses on the organized markets and I think Donald and Clyde and Tam, you guys have touched on it a little bit already but in terms of DER's that are participating in the markets, assuming that there is sort of a baseline amount of information that the market operators are going to have about those resources, I'm curious whether there is additional information that might be necessary outside of the information that would already be provided by those DER's as a market participant that would be necessary for effective planning and operation of the system.

And if that isn't already sort of included with that resources information as a market participant, you know, how would you go about getting that information. I wonder if you can also kind of talk about this in the context of DER aggregations and the potential for an aggregator to sort of act as a funnel for that information between the individual DER's and the wholesale market operator and sort of the ability for it to provide not only sort of that static data for the DER's when they initially enter the market but also some of that dynamic data about the capabilities of sort of the collective resource and whether that may obviate the need for some of the data from the individual resources as well.

MR. LOUTAN: So as I said at the beginning the system planners need certain types of data to do their analysis, a stability analysis, other types of studies to determine if the system is stable.

When it comes to operations we need different types of data to participate in the wholesale market we do have requirements. So let's say you want to participate in ancillary services -- we have telemetry requirements, we have checks that we do.

DER would have to meet the same requirements as transmission connected resources. Now the reason being we have standards that we need to comply with. One of those is something called disturbance control standard whereas if anything happens on the system we have 15 minutes to react.

15 minutes and 10 second is too late right -- we could get fined. So if the expectation of the transmission is you provide 4 second data so that we can do this calculation then the expectation would be similar if DER individual was an aggregate, what about ancillary services providing things like that.

If they want to provide -- well this is not ancillary services, high-frequency response. We have certain timeframes where we need that response. The expectation of the transmission is within 52 seconds. We'd expect to see similar type response from DER, what are the parties able to provide these types of services.

MR. BAUMANN: Thank you, Mr. Bielak?

MR. BIELAK: Thank you, Donny Bielak, PJM. So from a market participating DER we would fully expect PJM operations and markets are constantly working together so the markets aren't going to implement something that's not going to get operations the applicable data that it needs to adopt it reliably.

So I have no concerns with that. With regards to aggregation -- aggregation can certainly provide benefits to operations. We typically talk to certain, you know, market operators and they manage entire fleets of generators but -- so we're used to calling on say like a unit by unit basis.

That would just be logistically impossible if we're trying to call down to every 10 kilowatt DER of the system. So if you aggregate them up to an appreciable level and we could work -- we could work with our, our markets on that to determine the appropriate thresholds for that, that actually makes things smoother and easier for an operational standpoint in order to be able to control these devices if they are being participating in the markets, because we just simply can't communicate with every resource if it's just too small.

So I would -- I would say that we would leave as far as determining those parameters operations and markets and our stakeholders would all work together to come up with an amicable outcome for that, thank you.

MR. BAUMANN: Finally Miss Wagner with the final words for this panel.

MS. WAGNER: Thank you , Tam Wagner from the ISO.

So with regards to participation in the wholesale electricity market I think we need to also kind of take a step back as to what the purpose of that participation is and ultimately from a system operator perspective is -- it's ultimately in order to deliver a reliability service and to like Clyde indicted from California, is there are requirements that we need from a responsiveness perspective and part of that is being able to have the -- whether it's the dispatchability of those resources or even just knowing what the response of those resources are.

But not to say that that needs to be done at a super granular level -- again it comes back to my previous point around what is that interaction from a system operator perspective with the local utilities or the distribution system operators and what have you.

And I think that relationship will define the nature of the data that's required and that's some of the work that we're doing with some of our initiatives with our local distribution utilities with like I mentioned, we've got over 60 utilities in Ontario that range in size and complexity.

And one of our -- our largest utility is the second largest municipally owned utility in North America so their capabilities are much more advanced than some of our -- some of our smaller utilities and such and so we're working to find what that ideal solution is from a data requirement perspective, recognizing that there are specific needs in order to maintain reliability that currently we impose on those more traditional generators and we need to determine what that equivalent data requirement is for the distributed energy resources.

MR. BAUMANN: Thank you all that concludes the Panel 4 today. I want to again take the time to thank the panelists not only for their time and effort in attending the Conference today but for providing us with informative answers on this panel.

We will adjourn until 10:45 at which point Panel 5 will begin, thank you very much.

(Break 10:33 a.m. - 10:50 a.m.)

MS. SCHMIDT: Alright welcome to Panel 5 and thank you all for being here. Panel 5 will discuss the -- How DER's are currently modeled, particularly in planning and operation studies and what we might need or what we might want them to look like in the future.

And as a reminder for the panelists, please turn on your microphones as you speak and apparently people in the back are having some trouble so definitely try to speak loudly into the speakers thank you.

I'm going to announce the panelists as well. So owe have Shay Bahramirad, from -- she's the Director of

Distribution System Planning and Smart Grid Innovation at the Commonwealth Edison Company;

We have Jens Boemer, is the Principal Technical Leader in the Transmission Operations and Planning Group at Electric Power Research Insitute;

We have Ning King who's the Staff Scientist at Argonne National Lab; we have Dennis Kramer who is the Senior Director of Transmission Policy, Stakeholder Relations and Business Development at Ameren Services Laboratory;

We have Marija Prica, who is Assistant Professor at the Case Western Research -- sorry, Western University and she is also a visiting professor here at FERC who helped us with our DER studies so thank you again Marija Prica.

And we have Binaya Shrestha, who's the Regional Transmission Engineer at California ISO and we also have Ganesh Velummylum who is a Senior Manager and System Analysis at NERC, and we have Brant Werts, who is the Lead Engineer in DER Technical Standards at Duke Energy Corporation.

And we're going to jump right into questions 1 and 2. So our first set that we're going to look at are -- What are current and best practices for modeling DER's in different types of planning operations and production cost studies and to what extent are capabilities and performances of DER's currently modeled?

MR. SHRESTHA: Good morning my name is Binaya Shrestha and I'm with California ISO. And first I would like to thank for this opportunity to be part of this panel and to answer the question, you know, the current practice at the California ISO in transmission planning group.

Just to give you a little bit of context my colleague Clyde tossed out some numbers and that was related to renewables and behind the meter solar and I want to give out some numbers in terms of DER.

When I say DER here it includes load modifying DER's like demand response and energy efficiencies and also the generating resource-type DER's like behind the meter PV and could be in front of the meter PV.

So with that said what we're seeing for the planning horizon for next 10 years in terms of the DER capacity is this is based on California Energy Commission forecast. They're responsible for coming up with the load forecast which we use in the planning studies. So 2017 we had a little more than 7,000 megawatts of DER and the prediction for it to grow by 2030 is close to 30,000 megawatts.

So given the system which is about 50,000 megawatt today and the gross load is projected to grow to a little less than 60,000 by 2030. So we're talking about almost 50% in terms of capacity but we should keep in mind that a big portion of his is from behind the meter solar which has, you know, relatively less impact on out in the peak timeframe when we're talking about the peaks and all that.

So going back to the current practice how we model this is the planning studies -- like I said if we're creating a case for 2030, we have to model about 30,000 megawatts of this DER and more than 50% of that is from behind the meter solar.

The other big component is the uncommitted energy efficiency and the other components are like demand response and known PV behind the meter generation. So, when we go about modeling this for a load modifying-type DER like demand response and energy efficiency, those are modeled as aggregated negative load at TND interface.

And for the generation resource type DER like behind the meter PV, those are modeled as aggregated single generator at the TND interface. And in front of the meter connected solar are either modeled as individual generator or it could be modeled as aggregated and really depending upon the size and whether or not the resource has the California market ID, whether or not it participates in the market.

So that's about how we model. So in terms of the options available for modeling interaction between transmission and distribution based on the current practice it's pretty much limited as you can understand, you know, the transmission model does not include detailed model for the distribution. It just stops at the TND interface.

So the numbers we can see other than, you know, the load will probably trip under certain contingency conditions in the transmission system so that's pretty much what we can see impact on the distribution side.

But there's a little bit more we can see on the transmission side because of what's happening in the distribution side based on how detailed we can model. So we can go into details like composite load model later in the discussion, but that's what I have to respond on this question, thank you.

MS. SCHMIDT: Thank you Mr. Shrestha, I believe that Miss Bahramirad had the tent up?

MS. BAHRAMIRAD: Shay Bahramirad from Com-Ed. Thank you for the opportunity to be here and part of the panel. Com-Ed is an electric utility and provides electricity to about 4 million customers.

In terms of answering your questions on the modeling I'm going to answer it from transmission perspective and distribution. At this point in city/state analysis the distributed energy resources connected to the grid are not explicitly modeled on the transmission -- sorry -- it means that the DER's are treated implicitly as negative load as part of the loads connected to the transmission grid.

For the current practice DER are not modeled also in dynamic studies however we are thinking about different ways of modeling DER's such as documented NERC guidelines. And that's something that we may consider in future with increased penetration of DER in our system.

As far as I know there is not an industry recognized best practices for this so far and currently there is no DER model for interaction between distribution and transmission.

On the distribution side we do interconnection studies for the DER connected to our system and we currently model them in distribution software side utilizing back-up transmission impedance and study voltage level.

We can determine to what level DER will flow back into transmission system and working closely with the transmission planner to determine if there is any issue on the transmission side.

Recently we've been working on a much bigger project it's a 10 megawatt load that and 10 megawatt distributed energy resources that is going to connect to a privately owned campus micro-grid. For that one we are planning on modeling solar as well as storage and other distributed energy resources and looking into the impact and the configuration as in an RTDS lab in Burma to understand the impact and refining the models.

MS. SCHMIDT: Thank you, I think maybe Mr. Velummylum?

MR. VELUMMYLUM: Thank you so much again for the opportunity to be here on Panel 5. I just wanted to and I know I'm going to say a speech here I know that's not my jurisdiction but I'm going to sell you two items here.

NERC and the industry have published two reliability guidelines -- I hope the camera could see this, so folks it's out there, it talks about -- I'm going to talk about current practices and then what the capabilities are.

So note to the industry stakeholders -- we have a great team, Brian Quinn, it's approved by the planning committees. John Mauro, you know, who's great and encouraging all of these different efforts, my team, my engineers continue to use this guideline Elusia Muhammad, to educate the industry.

What is the best modeling practice out there? So right now there are different types of models -- I'm going to talk to you about some of the models here. We talked about aggregation right? There are different types of models for aggregation we can use one type of model.

For detailed modeling the guideline talks to you about what kind of modeling you need to use. So there are information in there that current best practices that we had asked the industry to use, but again, I'm going to just say the speech. Like a real estate person right -- location, location, location.

Here I'm going to tell you models, models, models. Let's get the models in. We have the capability, they are there already and they're getting better, you know. We need to start using this reliability guidelines to capture those different implications.

Coming back to my colleague here where she mentioned about the BS is the balance system right, I mean it's Study 1 Phase, Study A Phase we know what B Phase, C Phase is going to be -- they're balanced. But when you talk about distribution it's unbalance because you can have a feeder with Phase A and Phase B 5 miles and at Phase C 20 miles.

You can't connect the balance with an unbalanced system -- you're going to cause problems, you know. So I think Argonne and Ning is going to talk about, you know, some of the tools that you're working how to get that, you know, figured out.

What I'm saying is that the guideline is there. It talks about different ways you can model them and what best level, KV level to model them. It talks about the megawatt -- what you need to look at and it talks about steady state studies use this model -- PVD1.

Now if you want to look at the capabilities that we talked about today -- frequency, affected control, volt, then you use the DER model which can capitalize all the different features that this device can be.

So the models are there, the reliability guides are there so I strongly encourage the industry -- now we have system and a modeling sub-committee that has different sub-committee that reports to them.

Like right now we have a load modeling task force, PPMBTF that are great task forces that are working with the industry, educating the industry, coming up with ramping -- so if you want to participate I'll be more than happy that these committees exist.

We're constantly working with the industry because NERC doesn't own this data, it's the industry that owns the data, they own the inverters. So we are working with the industry to help us educate everyone else, you know, different challenges that people are experiencing and that's why the different sub-groups within NERC that help to put this reliability guidelines and we are continue to refining them.

So it is there but we just encourage people to start using them to satisfy Mach 32 requirements that a transmission owner, planning committee needs this information from the distribution provider, the load entity, so I encourage people to start using this reliability guideline.

They are posted on our website, you know, under reliability assessment and system knowledge, they're all up there so I encourage it, thank you.

MS. SCHMIDT: Thank you, we're going to go down the line starting with Miss Kang?

MS. KANG: Thank you Commissioner, thank you Ganesh for already the introduction. So I am from Argonne national Lab. So we are a non-profit organization reporting to the Department of Energy and we conducted research and development for the public benefit.

So I think I just wanted to go back and reiterate what Ganesh mentioned this NERC published DER report -- actually on guidelines on what's the best practices for modeling of DER's. And ideally, because of the high penetration of DER's they are creating potential threat to the reliability of the host distribution transmission system.

We wanted to actually include the entire distribution modeling and all the DER's in that study but we all know it is simply cost prohibitive for certain analysis like transient studies and dynamic studies.

So it is very much appropriate to actually simplify the modeling practices and currently there are two practices which the first one is aggregation of modeling of similar characteristics together.

And the other one is actually to use reduced order dynamic equivalency modeling for especially for dynamic studies. So when you do the aggregation there are several criteria you can use of modeling. The first one is you can actually the NERC report refers to it as a modular approach.

The first one is you can aggregate resources based on the resource type. Some of them are dispatchable, some of them are non-dispatchable so it makes sense for the operators to separate those resources so they can make the best dispatch scenario rather than the worst case scenario.

And then the second one is obviously you can differentiate DER resource types of interconnection centers and you know we have variable versions of DER interconnection standards such as IEEE 1547, California Rule 21 -- they have been evolving and they're going revisions so they will obviously have different voltage, frequency MISO requirements.

So it makes sense to separate legacy and future DER and another criteria is actually to separate the DER resources by the NOPR from technology. Obviously in interface DER's -- they vary very differently from synchronous generation interface DER's and the, sorry, the DER types are inertia-less and they react much faster, so yes this is my brief answer to your question.

MS. SCHMIDT: Thank you, Mr. Kramer?

MR. KRAMER: Good morning and thank you. I would like to thank FERC for holding this Technical Conference. I think the first day was very informative and hopefully you'll find the second day similarly.

As you said my name is Dennis Kramer, I work for Ameren Services however today I'm speaking on behalf of the more than 40 MISO transmission owners that are currently members of MISO.

DER -- there's three simply questions -- what is it, where is it and what is it doing? And those three questions -- the answers to them is a little bit different depending on what studies you're doing. In other words, in planning, operations and production costs -- the three you have here.

In planning I don't need to know what it is doing today and I don't need to know what it's going to be doing in the next hour but I do know what it's going to be doing in the next 5 years. I need to have those projections.

I still need to know what it is, what is its capabilities and I also need to know where it is. But I don't need to know necessarily on exactly what feeder it's on. I may need to know where it's aggregated up to some type of sub-station bus that would probably be sufficient, at least with the current type of penetrations we're seeing today in MISO, I'm going to clarify that.

This is what I'm speaking about today is strictly around the MISO footprint of the current penetrations and what we expect to see going forward in the near time. Operation's is a little bit different -- I need to know what it's doing right now.

I need to know what it can be used for and called upon to do. There the question becomes is what's that worth to me? How much am I willing to cost customers to pay to get that capability -- that's uncertain at this time. And production cost there you're dealing -- I don't want to get into markets but what are you expecting this to be performing? Is it going to be in a market or is it going to be under some type of state policy or state program that's encouraging a certain type of behavior on the part of that device?

And you know, just referring to our colleague on the panel from FERC, we think that the FERC efforts have been very good in starting the process around the planning aspects for the transmission. But we do believe, and I think the folks from OMS that were here on the previous panel expressed it very well.

Within MISO we have many different states, most of them are vertically integrated and that we really need and we're working in MISO to have the states work with the distribution companies and transmission companies to come up with what are the data requirements that we need both from a planning and operational and also from the markets, with MISO's involvement and also the FERC requirements for reliability -- what are those datasets that we need to perform the functions in all three of these aspects that you've listed, thank you.

MS. SCHMIDT: Thank you, Miss Prica?

MS. PRICA: Thank you again. Thank you for letting me part of this panel and I would also like to thank people that I was working with for a year here, that it was really for me a unique experience because I learned a lot from you guys and I hope you learned at least something from me.

To talk about the modeling DER modeling today it really depends on the software that the utilities are using. Because the utilities are using mostly commercial software, some of them are maybe a little more advanced, some of them are not.

One thing that is difficult for them is really to switch from one to another because that requires people, that requires time, it requires funding like to be able to do that. The model itself, if you look at the DER models they can be as simple as net load but is usually used for performing study analysis, it can be some type of dynamic like voltage control that can be used as that model but is usually used in stability studies.

If you talk about real dynamic studies there is not really the end models, aggregated models that can be used on a transmission level. In that case the question is can they be developed? Or also does best cases we need to include the distribution part of this system to be able to do entire system for dynamic analysis.

I did talk with some of the providers and they said that their models, DER models that are for the dynamic that can model or they can support the 5047 requirements, however the main problem there is not the model itself but parameters.

Because you can have a model and you can think about that, if you can create a basic -- unless you know what A, B, and C are like you cannot really solve the problem. The same thing is with a model. You can't have a model like so, but if you don't have proper parameters that model will not give you accurate results. I think that is the biggest problem because we can develop models but it is up to utilities to verify them.

Because as a university or as developers we should have the ability to go to a utility and to plug in the models and like check them but they do have the ability.

One question was also about interaction between D&D. There is no at the moment standard approach to that, however there are some things that software developers are doing. One of them and some of you already know is simple, but that software has the ability to connect transmission and the distribution.

The biggest problem in connecting the TNB is that the models that we are using. For transmission we usually use a single phase, representation balanced system. If you look at distribution it is three phase balanced. Trying to connect balanced and unbalanced model is really difficult because like you cannot an unbalanced system balanced but you can make balanced unbalanced.

In that case like to really connect them correctly, it really requires to analyze transmission as a three-phase unbalanced system. However, the second approach and I think some utilities prefer that approach that is it is practically two level process.

One -- first step is to analyze one separate transmission then based on the data from transmission analyze distribution, then put it back to transmission and do our analysis. In that cases utility do not need to learn new software or new tool, they can use existing stuff.

But again, there is a need to make a connection between two softwares to be able to talk. And also when we talk about the modeling, especially for the accuracy of the modeling and I just mentioned previously when we try to build our utility distribution site to plug in the transmission we always want to have a three-phase.

However, when we connect PV's on the rooftop, they're not going to create as three-phase, they're single-phase and the question is really like what is that margin other than they are making and how that can impact the real studies that we are doing in transmission.

MS. SCHMIDT: Thank you, Mr. Shrestha?

MR. SHRESTHA: Alright thank you, this is Binaya Shrestha, with California ISO again. I just wanted to elaborate a little bit on specific to what model do we use. So like I said in the forecast we're seeing high interest and it's been like that for the past 3-4 years and that's why studying perhaps the three-cycle we started modeling behind the model PV explicitly in both our flow and for dynamic study as well.

And three years back we did a pilot project trying to understand impact of the DER because that's the first time we have seen the very high projection for DER growth. And in that study we -- we tried to model aggregated generated at TND interphase representing distributed solar using a second generator model.

And for that, like we heard yesterday too, it's a humungous task if we try to do that to model actual generator as an aggregated generator and come up with the incremental evidence and all that to do each -- at each TND interface, that's a humungous task.

Anyway we did that and we learned a few things from that study. But around the same time -- at that time we were using composite load model just for the dynamic representation of the load but there was no PV incorporated at that time.

But around the same time the composite load model modeling group came up with the Edison of PV1 model to represent dynamic part of the distributed solar and we started using that.

Since then for past year cycle we've been using load model with PVD1 composite load model for the dynamic study for representing this distribute solar and as Ganesh mentioned, you know, there's been improvement to that so now just recently the modeling group came up with the better model to represent distributed solar which is known as DER A which as Ganesh mentioned it has a capability to model lots of other functions that one -- a smart inverter can have based on the, you know, the requirements coming out from the IEEE1547 it can have 5 or 6 different operating modes in terms of control so this model can -- in a simplified manner can represent that.

So the model is evolving and we are using whatever is available out there using the best practice and I think it is also consistent with what is put out in the staff report in terms of the -- one of the different modeling efforts. So I just wanted to point out that that's what we've been doing for the past three cycles.

MS. SCHMIDT: That's great, thank you. We have Mr. Werts?

MR. WERTS: Thank you. I'm Brant Werts, at Duke Energy. Although Duke Energy has many regulated utilities I'll be answering mostly in terms of Duke Energy progress located in eastern North Carolina.

This is because DEP leads Duke Energy in terms of DER by megawatt capacity and percentage of generation and this is driven by per QS, up to 20 megawatts. I wanted to follow-up on the DER forecast conversation of the previous panel to talk about what should we model in our planning studies.

Although DER projects are modeled in our transmission model as an aggregated generator, at the transmission type, by resource type -- this is only one state that decided to move forward with construction. Modeling the possible transmission impacts of every DER that applies for interconnection is not practical.

We'd have to study every contingency for every scenario. Duke Energy projects are currently working to make known transmission constraint areas available to both developers and our distribution system so they can avoid installing more DER in areas where it may be to expensive transmission upgrades.

This still leaves many challenges in forecasting DER in the future and challenges with how we would model that in our planning studies, thank you.

MS. SCHMIDT: Thank you and I think we have Mr. Boemer?

MR. BOEMER: My name is Jens Boemer, I'm with the Electric Power Research Institute which is a not for profit institute dedicated to the public benefit. I would like to shed a little bit more light on the nuances of the modeling of DER for transmission planning studies, in particular dynamic stability studies.

As mentioned, we have a variety of models available in the leading software platforms used here in North America to model utility scale DER and what that means in the modeling world is a DER directly connected to the distribution bus of a sub-station or connected to the distribution bus through a dedicated feeder that is non-load serving.

So those models which are generic models in the software libraries are available and have been used by RTOs and ISOs for several years already. Let's add the modeling of retail scale DER which either residential, commercial or industrial DER that may offset customer load and that may also include single phase or three-phase interconnections in their kilowatt scale.

They are much more challenging to model in transmission planning studies simply because it -- as mentioned by the other fellow panelists, it is impractical to model each of these DER's individually in a system-wide study.

So in one way or the other the information needs to be aggregated and potentially dynamic equivalent models need to be developed. And the good news is there were substantial improvements in the area of aggregated and dynamic equivalent modeling in the recent years which finally led to the development of the so-called DERA model that was mentioned by some other panelists before.

We would just like to caution at this point that this model has not been applied widely to date and therefore industry has very little experience with the accuracy of this model for analyzing the impact of DER on bulk system reliability studies.

Further research is therefore needed to explore whether these latest models are sufficient and whether they may need further improvement and we believe that the work that Argonne National Lab is performing with co-simulation approaches and similar, may help inform us and the industry to what extent these existing models are suitable and practical for transmission planning studies.

We also expect and I would like to stress that because it's a new, new development I would say that we see value in using models like these aggregated DER models as well as the existing utility scale DER models in order to inform decisions by the authorities who govern the interconnection requirements what type of economic performance should be required from distributed energy resources in the context of interconnection standards like IEEE Standard 1547.

I'm going to spare my comments on other types of modeling including production cost modeling but if there is interest I will be happy to answer further questions, thank you.

MS. SCHMIDT: Thank you, Miss King?

MS. KING: Hi Commission, I just realized you actually have and I started asking a follow-up question of the interaction between the TND but several fellow panelists have already started addressing them.

I also wanted to provide my comments but with your permission otherwise I'll let you ask the question first then I will.

MS. SCHMIDT: Yes, please do, the next question was going to be a call for if anybody else has comments on the modeling between distribution and transmission as well as any further tools that might be available.

MS. KANG: Thank you, so I'll just go on, yes, so at Argonne National Lab we have been or actually conducting, researching in this regard since the beginning of 2016 and we have been working closely with NERC as part of the support for their essential reliability service working group and the DER task force. And we have Nicole, she's our collaborator and also Ganesh from NERC and so they can also provide some insights into some of the work we do.

So in terms of the options in my mind there are three so the first one I wanted to highlight is so-called TND combined modeling. So this is related to the work we did with NERC so I think we actually modeled a combined transmission description system in one simulation platform that is net lab single link platform.

So in this TND combined modeling we modeled, we couldn't do a two area system on the transmission side and hydrochloride, on the system on the distribution side. We also connected all sorts of DER's on the distribution system modeling.

And so with this representative system we conducted six benchmark case studies and we looked at area impacts of DER on the reliability of bulk power system including voltages stability, dynamic stability, frequency stability and in one case study we actually looked at, you know, how increasing the DER penetration will displace conventional synchronous generators and reducing the total available energy in the whole system.

So we observed, you know, system frequency response, upon, you know, a disturbance so you can see, you know, the system would have a much lower frequency after the disturbance and also much higher and longer oscillations after the event and so those are -- those huge big swings are not actually attempted by our system stabilizer so they can potentially cause many other equipment to trip and cause, you know, cascading failure to the system.

So this tool is very useful itself but then that would lead me to another option I wanted to discuss which is TND cross generation tool. So what the difference between this one and the previous one is in this tool we are actually coupling individual transmission system simulation tool with another distribution system simulation tool.

And again, we also have an ongoing project as --

yes also highlighted where we're developing a co-simulation tool we're coupling PSSE on the transmission side with open DSS on the distribution side. The idea is that this tool will be able to model actual combined TND system and allow us to perform a real life contingency study.

And the third one I'd like to highlight is just a PVD1 model as other commenters have highlighted. This one basically is an aggregated -- the economic equivalency model of all the DER's on the distribution system side but this is actually connected on the transmission load so it can be actually modeling transmission systems in simulation software.

I believe that PSSEPS have already included this model in the transmission side so you can conduct these studies, so there's three options, thank you.

MS. SCHMIDT: Thank you, we have Miss Bahramirad.

MS. BAHRAMIRAD: Thank you, Shay Bahramirad from Com-Ed. I wanted to add like just two things about the gaps on models in software. And for distribution the current model choose -- they allow for modeling the different and manual load profiles on static commercially available tools.

And the tool can utilize some specifically just for advanced inverters that are a required part of the new IEEE standards and Hawaii Rule 14 or California Rule 21.

And those functionalities we can currently model them on the -- during the customer interconnection studies since on the distribution side there is a lack of time studies analysis and distribution planners manually model different worst case scenarios which means a high generation low load, or high generation high load and low voltage and N minus 1 contingency.

I wanted to bring one industry effort to your attention which is worth taking a look at it. IEEE is leading an effort on identifying implementation challenges of smart inverter associated with distributed energy resources. That effort is requested by Department of Energy.

We'd be contributing to this effort by looking into the impact of implementation of smart inverter functions on distribution system planning. All the comments that I previously mentioned and you heard from fellow panelists is part of that viewpoint.

Besides the effort is going to analyze the potential impact and challenges of different functions of distributed energy resources and smart inverter for voltage and the active power control -- the output of different distributed energy resources like valuable DER like wind and solar can change significantly due to external conditions such as cloud movements and wind speed variations.

And that's something that this report is going to address. I just wanted to bring it to your attention. The report will be finalized in the next couple of weeks.

MS. SCHMIDT: Great, thank you and one follow-up to these first two sets of questions before we move on. I was curious to know -- this might be more for Mr. Shrestha -- the DERA model that was created -- I'm wondering how that compares to the more recent PSLO releases in their composite load model?

MR. SHRESTHA: So on a high level this DERA model allows us to represent distributed solar capabilities in a little more detail. For example the previous version which was using PVD1 model it -- it doesn't allow to model the frequency voltage regulation, frequency regulation capability that a smart inverter is going to have because of different standards.

So the DERA model is kind of like an in-between from that basic model to the much more detailed solar PV model which is used for solar PV connected to a transmission system for the individual generator model so it's kind of between the halfway of those two.

So that is the basic difference. So the reason it came about is because, you know, we pretty soon realized because of this newest standard coming out mainly from IEEE 1547, California Rule 21 to have this inverter -- this capability, you know the industry realized that the basic model which does not allow you to model the voltage regulation of sequential model, is not adequate, so that's the basic difference between these two models.

MS. SCHMIDT: Thank you, Mr. Velummylum?

MR. VELUMMYLUM: Yeah thank you very much and I couldn't agree with my colleague here from Cal ISO but again I'm going to do a sales speech.

Section 2 of the reliability guideline distributed energy resource modeling September, 2017 was published, page 21 talks specifically about the DER and it's called a model capabilities.

I can read them all one by one -- it's about 10 bullets if you want. Frequency control, droop control, asymmetric date back modeling -- and my colleague here talked about we have all these parameters you know, like constant power affect whether caught at low and high voltage including a 4 plan piece vice, and again and we can go into all these details.

This ramping limits and so forth it's all in chapter 2, page 21 of the reliability guideline. It talks specifically, you know, the difference between PVD1, you know and just like my colleagues said.

One of the things in system analysis yes, we have these capabilities but what about the parameters? Let me give you an example -- droop control, droop setting -- 1%, 5% right? What we do at NERC we push it, we stretch it. We test it with 1% under a large contingency.

We test it with 5% under a large contingency. So what we do is we book it -- obviously my management, John Moran, stress the system, stress the system to see where it breaks right? You know how far can we go and that's what we do. We look at different parameters, we look at the bends like 1%, 5% and different date bands and we study them under different contingencies.

We push it and then we see what are the challenges there. So sometimes the challenges there -- you're right, you know, we don't have the parameters but then we have to start playing with the parameters now that we know we can model it, that's what the planner needs to do -- try to play around with the numbers and try to see.

And then we educate the industry under this setting, under this fault, this is what you get -- the response from with respect on that there, how close you get to point C -- that's what we do. And I know we have a FERC filing 794 that we do and I'm not going to get into that, but you see a lot of these comments in there how we study -- especially Eastern interconnection.

But I challenge planners to start, you know, challenging themselves -- play with the parameters, try to figure out what is the right settings, then we can educate the industry, the operators, you know, under this condition this set of parameters should be used.

So I'm going to say you know, I mean, it's a challenge but we have to, you know, take that bold step and play with the parameters. If we don't have the information play with it and see what we can get out of it, thank you.

MS. SCHMIDT: Thank you, Mr. Boemer?

MR. BOEMER: Jens Boemer with EPRI. I would like to complement the information that Ganesh provided was a bit more detailed and also further recent developments to get you up to speed on what happened since the publication of these valuable documents by NERC.

As I mentioned before the software platforms have the generic models for utility-scale DER already implemented pretty much across the whole list of software packages. When it comes to the PV1 or PVD1 models, all the platforms like GE's PSLF, PSSE from Seaman's power simulator, and PTP side, they have this previous model which sometimes is called PVD1, sometimes called PVI implemented as stand-alone models.

And then more recently in the last couple of months following extensive discussions and expert specifications and also benchmarking under EPRI leadership in collaboration with WEC and NERC the DERA model has been included in the latest releases of these four nature simulation tools.

As a stand-alone model and this is what I'm trying to have it -- I'm heading it is that if you want to include the stand-alone model for distributed resources into the existing power flow cases in a meaningful way, you will have to add information on the distribution feeder.

Now in bulk system studies you do not want to model all the details of the distribution feeder at this time and so far we have not seen that it would be necessary to model all the details. So in that respect, some type of equivalent distribution feeder data for the impedance in terms of resistance and reactions of the circuits needs to be added, explicitly to those power flow cases in order then to extend the power flow model with the dynamic equivalent model PVD1 or DERA.

This extra step to extend the existing cases with additional elements can be quite an undertaking. You could either do that manually by going to every load bus and adding the step down transformer and line and then the distribution bus and then adding the generator model itself.

Or you come up with automated scripts to do so which is possible and we have done with our members in the past. Now the major next step that we expect to happen sometime this year is that this new DERA model will actually be integrated in a modular way or in a more static way into the composite load models that have already been used extensively in the industry in the past year.

And what that would help transmission planners with is that instead of having to add all these additional elements either by hand or by coming up with scripts to do so automatically, they could simply use the composite load model which already includes all of these elements, replace the load at the transmission bus and then have the full representation of the load next to the DER as good as we are able to do it today in these types of studies.

All that said, even with the availability of these models the very next question is what shall be the parameters to fill these models with? And I think this is what the previous panel already addressed to a certain extent, but more research, more collaboration will be required going further in order to understand what are the critical parameters of these new models?

And I think I mentioned it earlier, possibly some of the critical parameters relate to the potential light area tripping of DER due to frequency of voltage regulation -- voltage disturbances and with the publication of the new IEEE standard, this may become less of an issue going forward.

However, in order to keep that potential issue of the tripping small, then the new IEEE standard would have to be adopted and implemented in all those jurisdictions that are expecting significant growth of DER as soon as possible -- because if there was any delay in implementing the new standard, the aggregate amount of DER that would trip close to frequency or voltage disturbances along nominal values would continuously increase and therefore the risk associated with that tripping may also increase and therefore the modeling will become even more important.

So there's a balance between using the models to inform decisions on implementing new standards, but also using the standards in order to be less in need of perfectly accurate models.

MS. SCHMIDT: Great, thank you and then we have Miss Kang and then we'll move on, kind of switch gears to the other questions.

MS. KANG: Ning Kang, Argonne National Lab. I just wanted to briefly complement on what Jens just said. So I think I wanted to -- I couldn't help but notice the discussion kept coming up you know, that the discrepancy on the modeling on the distribution side, on the transmission side is specifically for this school -- the group of studies where we do extend the distribution system modeling and, you know, conduct TND closely in relation.

So for the TND combined modeling work we did so we actually modeled both the transmission site and distribution site with three-phase modeling, balance on the transmission side and unbalanced with single-phase, double-phase laterals on the distribution side.

And for the TND cost simulation to that we are working on so we keep the three-phase balanced on the transmission side with sequence components representation but on transmission side again we model the distribution as unbalanced as it is.

We've actually developed this sequence and base quantities conversion on the TND interface to facilitate such studies, thank you.

MS. SCHMIDT: Great, thank you. I know a number of us have been studying the DER's, we're going to let the other folks ask questions with a quick note that one of the members of our team, Louise Nutter who has done a lot work with DER's is not here. We just wanted to recognize her quickly.

MR. PHUNG: Could you further discuss how or if the outage of DER facilities is considered in current contingency analysis in studies and if they are considered, how are these contingencies developed?

For example how are the contingency sizes chosen?

MS. SCHMIDT: Ms. Prica?

MS. PRICA: Thank you. I will talk but from the point of view of the utilities for metering connection.

Because of the very small percentage of DER's in their system, it's maybe like less than 5%, they don't incorporate them into their interconnection studies because they are so that even including them doesn't really change much because of the amount that is known that is connected that are not part of the DER's in the service area but the transmission, but those amounts are very small.

MS. SCHMIDT: Okay, thank you. Miss Bahramirad?

MS. BAHRAMIRAD: Shay Bahramirad from Com-Ed. As I indicated previously the DER's -- they don't get explicitly modeled in the transmission system. On the distribution side there's a lack of time studies analysis -- we don't have that type of -- we didn't have historically that type of data.

Now it's been a bit different by collecting the data, we have installed smart metering in the past couple of years and we have started looking into how we can -- how it looks like if we want to create time studies analysis for on the distribution side.

The way we are doing that type of contingency analysis is distribution planners manually model different worst case scenario from N minus 1 contingency depending on the terminal design and depending on the configuration.

We look at the high generation and low load as well as no generation and high load and the different low voltages on distribution system.

MS. SCHMIDT: Thank you, next was Mr. Shrestha?

MR. SHRESTHA: Thank you this is Binaya Shrestha with California ISO again. So just to answer the question on whether or not DER facilities are actually included in the contingency analysis from CAISO planning study perspective, we do not necessarily include individual -- individual meaning -- individual aggregated and DER at the TND interface as a contingency event, the reason being like other fellow panelists mentioned that it's not significant enough just to look at the individual DER at the TND interface to be taken out as a contingency when we're taking like 800,000 megawatts units out as a frequency integration -- it's not significant enough.

But what we do to capture the area wide tripping -- possible tripping of this DER is doing a sensitivity study on the output level of this DER. So for example, let's say our baseline scenario we have just for example, let's say 30% output dispatch from this DER behind the meter solar and then during sensitivity we might take 10% output or maybe no output from these DER's to see how would that impact.

So that's how we cover contingency on the right area DER tripping. The other thing I want to mention is in the dynamic simulation, you know, because of the settings --

the trip settings that it has in the model, we have observed that, you know, there could be a significant tripping of this behind the meter solar for a frequency or a voltage event at the transmission level.

What we have not seen is it causing any significant stability issue or maybe a criteria violation either but what we have seen is the resulting voltage performance and the frequency performance could be -- could be a little bit different, you know, had these units behind the meter units not tripped or had they right through the event.

So we are seeing that kind of impact but going back to contingencies, not explicitly modeled as a contingency.

MS. SCHMIDT: Thank you, Mr. Werts?

MR. WERTS: Brant Werts, Duke Energy. We are not currently looking at the loss of all DER as a single contingency. We do look at the loss of DER in an area such as specific as the transmission line, loss of DER associated at that transmission line.

One thought would be now that we have more DER in our Duke Energy progress territory, they're our largest unit -- that would become our single largest contingency but we don't believe that we would lose all of our DER at the same time such as the solar eclipse where we saw a significant loss of generation but we knew that it was coming.

The biggest challenges to avoid having this single contingency event where you could lose all of your DER and to avoid that occurring you have to be aware of where are all the voltage and frequency trip settings for both DER and transmission connected PV generation and be aware of some of the findings from recent NERC alerts that have kind of shown us that maybe the response of the inverters is not what we expected for both transmission and distribution resources and that we need to make sure that we're working with our developers that we don't have this case in which we could use a large segment of DER making it a single contingency, thank you.

MS. SCHMIDT: Thank you, Mr. Velummylum?

MR. VELUMMYLUM: Thank you again. I want to comment to Jens comment about modeling is in the modulator approach. I'm going to preach that again it's in the reliability guideline -- I think its figure 5 on page 6.

So what it tells us is that everybody is familiar with the concept of consequential load loss, a fall on a circuit, you trip that -- the load is lost. Now I'm going to use the term consequential DER loss. Just like how we lose loads -- if you model them in your models whether it's modulated -- they will trip based on the contingency configuration right?

So coming back to models, you have to start putting them where they are supposed to be designed. So everybody knows base cases they don't model breakers but it's all in your contingency file that you tell it which circuit to take up.

So if you model them at whatever process like how it's supposed to be modeled and introduce contingencies that you take, it will automatically drop that amount of DER. The concept is that we've used a concept for loads, it's there. It just happened.

Get it in the cases, model them and your contingency files should take care of them if they are, you know, the configuration do represent the breaker to breaker in the real world, thank you.

MS. SCHMIDT: Thank you, Mr. Kramer?

MR. KRAMER: Thank you, Dennis Kramer for the MISO TOs. In general in MISO we do not explicitly model the DER facilities connected as a distribution system when we're doing contingency studies.

However, there are situations where we may be aware of distributed energy resources on behind the meter that we would include in an analysis on a specific targeted local area. We would modify the load possibly to do an additional contingency or sensitivity analysis, but that would be on an individual case by case basis rather than just system-wide, thank you.

MS. SCHMIDT: Miss Prica?

MS. PRICA: Marija Prica, Case. I would just wanted to follow-up on what's something that Shay said about distribution modeling and particularly you're looking at the whole distribution site.

At the moment the tools that are available to the distribution systems are really more static analysis. But they also they don't include anything about 1547 that you will see in the future and that will be really a huge challenge because like here you will have especially in the areas that do have a lot of DER's, you will need to really properly model them to be able to provide proper analysis and studies so that you can see there what is happening in their system.

However, the 1547 as far as it was described in some utilities is really a set of options. And independent utility depending on the area, depending on the state but each utility probably will have their own options followed up with 1547 but also for the same options they may not have the same settings, or like the same requirements for their devices.

In that case we're developing general models. It would also be very difficult because like all these models will be a consequence of how the 1547 is applied in a system

-- in different systems.

It means that practically, even if you develop models somewhat now, we will also need to practically to enroll them as progress, as the utility gets more comfortable with 1547 because like at the beginning like I think they're trying to find the minimum changes -- like how to implement the model.

And at that level there would be a lot of effect on the analysis however, as time progress this will change. In that case every time when they decide to put on a new option of how to use the DER's in their system, they will need to also develop new studies.

With developing new studies they have to have proper models meaning that like practically for the old, the analysis at the moment like as we heard, like it can be some type of the composite model that does include some level of DER's if they are larger, but then these models will also need to be modified such that they do correspond to the new 1547 rules, thank you.

MS. SCHMIDT: Thank you, Miss Bahramirad?

MS. BAHRAMIRAD: Thank you, Shay Bahramirad, Com-Ed. What I forgot to mention I should have talked -- I specifically talked about N minus 1 contingency and what I should have added was if you are currently not really accounting for under-frequency load shedding or related studies due to low penetration of the distributed energy resources in our system.

However, we see the need for a mechanism to capture and account for reduced loads that will be account for the under-frequency load shedding in distribution systems similar to N minus 1 contingency.

New businesses are doing a 5 year plan capacity studies. Another thing to consider is that -- that you heard multiple times about the lack of models, dynamic models in distribution system and our studies are static, is to have some sort of a test such as varying the loop to look into the configuration and the impacts of these distributed energy resources and the contingency analysis as part of the planning so we can make planning in more intelligent decision in terms of designing the distribution system.

MS. SCHMIDT: Thank you, Mr. Boemer?

MR. BOEMER: Jens Boemer with EPRI. I would like to contribute to two topics, one is the planning models and the other one is more like operational planning with regard to the planning models. I just wanted to reflect on what Marija said about evolving models and how they may have to change depending on which performance categories of IEEE Standard 1547 may be selected by states.

We do believe that the way the DERA model has been specified to date does allow -- to represent different category assigned DER with the same type of model by changing the parameters that this model uses.

So the model is generic in that way that by adapting the parameters it should be able to represent different DER, assigned to different economic performance categories like right through requirements of IEEE Standard 1547.

Whether that statement is fully true will need to be shown in further research and experience but we hope that the model is prepared for the flexibility that the standard offers.

With regard to operational planning and you know, considering large scale outages or tripping, in the near term we do not have any knowledge at this point that any RTO or ISO would consider aggregate levels of DER as the most severe contingency in the real time contingency analysis.

That said, it really depends on the penetration level of those DER that are prone to trip and when I said prone to trip is that one may not have to perform sophisticated studies in order to get a feeling for the risk of these devices tripping. One can actually start looking at the, you know, the trip settings of the old IEEE Standard and the clearing times associated with that and then compare that to typical system disturbances that we have seen in the past to a certain extent to get a feeling for how close we are to a situation where larger scale -- larger area DER may trip.

But if say based on a desk study like that, one would come to the conclusion that there may be a risk of large area DER tripping then it would probably be wise to include these models also in the nearer term, real time contingency analysis.

There are actually examples over in Europe, for example, Red Electric in Spaina -- in Spain has done exactly that but they incorporate real time assessment of potential tripping of older winter lines in their control centers and therefore that allows them to dynamically schedule for operating reserves based on the risk level they pursue.

I would like to make two more points and one is I mentioned data -- we need data to really populate these models with meaningful information. The question is do we only need the data or does it have to be valid data? And if it has to be validated data which certainly is desirable, how can one validate this data?

And this is really a very open pretty much unexplored area at the moment right now. We hope to, to create some collaborative initiative across the industry that would allow management and validation of data for say smart inverters, maybe in form of a DER database that could be used in interconnection-wide studies.

That can be or could be linked to the certification that underlies the verification of compliance for meeting new requirements such as IEEE 1547 for example, the smart inverter certification procedures that are already available based on various state's interconnection rules.

But what about larger scale DER's -- say utility-scale DER? Even if we know all the exact details and settings of the individual smart inverter, we may not yet fully understand whether if you put several inverters together into a larger facility and then connect that larger facility with a collector system say to the distribution bus, whether as a whole, that facility would still comply with the performance that it is required to comply with.

And to date we see very -- a great variety of utility practices to actually verify for example, in commissioning tests, the performance of larger scale DER facilities. There are initiatives under way in IEEE for example, which try to standardize some of these verification procedures in further detail.

And it remains to be seen whether the associated costs to these procedures would balance the potential system benefits and reliability benefits but that's certainly another avenue for exploration for collaborative research and industry collaboration, thank you.

MS. SCHMIDT: Great, thank you all. At this point we will spend the last 15 minutes or so discussing question 5 and then any other questions that may come up.

MR. RICHARDSON: Yes so question 5 -- what methods are used to calculate capacity needed for balancing supply and demand with large amounts of DER's from the ramping and frequency control perspectives in determining which resources can provide an appropriate response?

MS. SCHMIDT: Mr. Shrestha?

MR. SHRESTHA: Thank you this is Binaya Shrestha with California ISO again. So I just want to answer this question in relation to something that ISO has in recent years started to do which is known as doing a study to come up with the flexible capacity requirement.

And this study goes about -- my colleague Clyde mentioned about this in his remarks in the previous panel. But to recap a little bit -- so how it's done is it starts with the survey that ISOs send out to all LSE's asking about their existing and next 3 years forecast for the DER installation.

And using that information and the load information from the load forecast and using profiles like publicly available profiles, we come up with the minute by minute load profile and within that we look for the maximum three hours of ramping required because of this injection of renewable resources.

Not only DER but all transmission connector renewables and distribution connected solar is part of that calculation. So once we come up with the three hour maximum ramp rate requirement -- let's say for example in terms of numbers for any particular month the 3 hour maximum ramping is let's say 10,000 megawatts.

That 10,000 megawatt gets allocated to the LSE based on their contribution to that ramping based on the amount of variable resource they have in their system. So that's the process that ISO takes in coming up with the flexibility capacity.

MS. SCHMIDT: Thank you, Mr. Werts?

MR. WERTS: Brant Werts, Duke Energy. So we use a combination of a radiance forecast and historical DER measurements from our distribution's data systems to come up with the forecast in the solar profile.

Using that profile we are able to forecast what the ramping needs and operating reserve needs would be for the future and then you can use the actual distribution's data to confirm what solar profile we have through the day to continue to update those needs based on the actual performance.

Historically we've used our simple cycle -- combustion turbines have been the most effective for handling the significant ramps that we see from our solar profile. And this has been because our appropriate generation hadn't allowed us to previously dispatch the solar that was connecting on our system.

But now we're looking at opportunities under a competitive procurement in North Carolina to actually control generation -- both transmission and distribution connected, to dispatch the DER inverter-based generation to actually respond to some of the challenges that have to deal with ramping.

So we're looking at technical capabilities to doing that at the transmission level and then working on down to directly dispatched down to 250K, thank you.

MS. SCHMIDT: Thank you, Miss Prica?

MS. PRICA: Thank you, Marija Prica, Case Western. I want to talk mostly about how we determine the resource capabilities to provide services. In Case we are supporting utilities in development and testing for different types of models.

But we are also working with them on system studies as well as administration projects. And those projects are very often in cooperation with EPRI and DOE. For the determining what can provide which response, practically our approach is distributor use testing or to use the real system, in our case it's the Case Campus.

At the moment Case has several projects going on, some of them are energy storage, PV related, some of them is energy storage related and some of them are building energy storage -- how to provide services to the grid.

Our expectation is that based on these demonstration projects -- as I mentioned before getting the real data is sometimes difficult however having the demonstration projects on the Campus really allows us to look at the models themselves, to verify them and also to look at the response of different technologies and different signals.

One of the projects we have is integration of energy storage. Practically that project by itself is really a multi-phase project. It has like we will do one model with how we can -- how the energy storage can respond to the wind variability and then the next project would be using the same device is practically how we can provide services to the grid.

Because the Case is part of the PJM market we do receive things from them and the idea is for example to use that same storage as a frequency manipulation but also not to just look at the credibility of the devices by themselves, but if they provide the sources to the market how they will impact our Campus network.

Because I think that that is one of the -- probably for me the biggest gap that they have today is using devices on the distribution side to provide resources on the transmission and market side without really having the knowledge of what is happening on distribution that this is in the middle of all of that.

By using -- by having like this type of demonstration project we are trying to really understand, depending on the size, depending on the feeder, the capabilities of feeder or the loads, mix up the load that we have on the feeders -- how different resources, when they do respond to the RTO or ISO signal, how they do impact that local network that they are replacing, thank you.;

MS. SCHMIDT: Thank you, Mr. Kramer?

MR. KRAMER: Thank you, Dennis Kramer from MISO TO. At the current time solar ramping is not a noticeable issue in the MISO footprint however we do have a sizable amount of solar that's in the queue and that's going to be coming on in the next few years.

But the current thinking is we've kind of addressed something similar when we had the huge influx of wind that we currently have. I know we had to adjust the variations in wind output and today in real time markets and set up the parameters of how they could participate.

And the key question I think that we're getting to is how do you determine which resources it gets to? Okay, is it an entity that is a market participant directly or is it someone who is an aggregator who is representing a series of smaller DER's and how do those -- we know where it is if it's a single market participant.

If it's an aggregator we will not know necessarily and I think that's where the previous panels have talked about is the aggregation and requirements for understanding what an aggregator does, what an impact of a command to that aggregator will, you know, what impact it will have -- which is mentioned on the distribution and the transmission level.

So that's where the need for data and understanding what that aggregator has in his portfolio, and where it's located and what will be the reactions of our system to any response to a market or command from the operation center, thanks.

MS. SCHMIDT: Great, thank you, Miss Kang?

MS. KANG: Ning Kang from Argonne National Lab. So I actually just wanted to circle back to the previous questions -- it's not a direct response for this question but it's in line with the whole theme of today's panel.

I wanted to echo what Shay brought up so she mentioned there's a lacking of an identity on modeling for right through a study's contingency studies and also as Jens brought up that even if those modelings exist, the validation is another challenge.

So yes, so from our associate experience, so we actually went ahead and we developed our own and then make a DER modeling in specifically to two platforms, one is a net lab, one is open DSS. So those in net lab we were able to implement those studies state and then make the DER modelings we were able to implement all smart inverter functions like volt control, constant power factor control, watt frequency control and also implement, you know, LNT requirements based on the IEEE 1547, specifically with the 2104 amended version.

And then for open DSS itself, it only comes with the study state DER modeling but it does provide a DIL user interface that where the user can later on the DER dynamic modeling and then integrate that with an open DSS so you can perform to then make DER modeling so that's what we are doing right now so actually we're able to, you know, implement our DER dynamic -- DER inverter response and that's makes as well as all of the controls as well as you know, the IEEE 1547 Standard.

So I think that maybe beneficial for the research community as a whole, so thank you.

MS. SCHMIDT: Great, thank you. With that it concludes the time we have for this panel unless there are any other really quick questions. I don't think so, so thank you all for coming. I wish we had more time to discuss this and pick your brains, especially thank you to Mr. Boemer and Mr. Velummylum for sitting on two panels consecutively -- it's appreciate and safe travels.

(Break 12:15 p.m.)

MR. KATHAN: So welcome back. We are now in the home stretch. We have only two panels to go and both will be on coordination. The first panel -- this panel will be focusing on issues in general about coordination and then the next panel that will follow is going to be on on-going coordination.

But I want to say just a few things that we make sure we say before each panel is that to remind everyone that we intend to focus this Conference on the technical and operational issues described in the notice. We will not discuss other related matters, including those at issue in any pending proceedings.

And also we have a lot of questions I know, and sub-questions on this panel. We will maybe not get to all of them but we will you know, let the conversation go as need be. And I'd also like to acknowledge that we have Commissioner Glick in the audience at this point and we're happy to hear everyone's perspective.

On this panel we have a David Crews from East Kentucky Power Corp.; Mike Esquerra from PG&E; Chairman Daniel Hall from the Missouri Commission; Pete Langbein from

PJM; Audrey Lee from Sunrun; David Owens, retired from EEI but came back to provide us his wisdom; Maria Robinson from Advanced Energy Economy and Jeff Taft from Pacific Northwest Labs.

So why don't we get started with the first question which is -- our first question is if the Commission adopts its proposal to require the RTO/ISO to allow a distribution utility to review the list of individual resources that are located on the distribution system that enroll in a DER aggregation before those resources may participate in the RTO/ISO electric markets.

Is it appropriate for the distribution utility to have a role in determining when the individual DER's may begin participation? So I'll open it up for comments. Mark?

MR. ESGUERRA: Yes, thank you, Mark Esguerra, Pacific Gas and Electric and I want to thank FERC staff for inviting us here to share our thoughts. So I'd just like to take a step back on that question.

The distribution utilities have the core obligation to maintain safety and reliability on the operation of the distribution grid. And so inherently they should have a role to ensure like the planned physical and operational characteristics of DER aggregations.

And something to think about is that T&D -

transmission and distribution systems, although they connect as an integrated grid, have actually been planned, designed and then operate very differently.

And so I'm going to speak a little bit about that before we get into like what are some of the steps for coordination. Distribution systems have been typically designed for one way power flow in more of a rate of design as transmissions have been designed for in network configuration.

Transmission systems are more designed for a more robust resilient nature which distribution grids are more designed for speed and efficiency and restoration.

And so you start to see some of this kind of play out with kind of the overall makings of the distribution grid. Largely speaking, the distribution grid wasn't designed for this two-way power flow so there's going to be -- without higher and higher penetrations of distributing energy resources and wholesale DER's or aggregated DER's participating in wholesale markets, there has to be some coordination in times of how to manage those flows.

And other things that I also want to point out are just the availability of the distribution grid. The transmission grid is designed as I mentioned, much more robustly. The distribution grid experienced much more exposure to outages and switching configurations.

Just to put things in context, a typical transmission line may experience one or two operations in a given year where a distribution line may experience multiple operations in the given month. When you couple that into some of the major weather events in terms of storms, you can see numbers of -- large numbers of outage occurring and impacting the various customers.

And so as we think about it the distribution utilities should have an opportunity to review how these DER aggregations are actually going to form and to be able to provide, you know, input on whether or not there's going to be safety and reliability problems with these DER's participating.

MR. KATHAN: Thank you, Mr. Crews?

MR. CREWS: Good afternoon, thank you. I appreciate being invited to participate. Kentucky is a cooperative in Kentucky. We have 16 members, we're regulated by the Public Service Commission in Kentucky which is somewhat unique because many cooperatives are not regulated by public service commissions.

We joined PJM in 2013 and we made application to our Public Service Commission to join PJM in 2012. One of the conditions that we were a regulated retail state and one of the stipulations that our Commission put on was that our retail customers not participate in the PJM market -- we've had some action at the Commission here related to EE aggregators participating, but -- and our Commission reaffirmed that EE and retail customers were not to be participating.

That said, you know, with that as background if we go this direction the question becomes is should the distribution cooperatives be part of this? And Marija from the previous panel talked about distribution feeders.

The fact of the matter is that -- is that the distribution system is not homogenous, must like the transmission system is not homogenous. The people that are going to -- that have the discretionary income to participate and purchase DER or batteries or things of that nature live in similar neighborhoods.

And depending on how the distribution feeders were originally laid out you could have a -- you could have batteries in one neighborhood on a feeder that if we operate them to settle back into the grid -- unbalances our distribution feeders and causes efficiency problems in that area.

So from that reason -- from an efficiency and a reliability standpoint it can cause problems. I'm not saying that it will but it's -- you know, in the previous panel they -- I think there was some thought that these would be, you know, disbursed amongst the distribution system but my believe is that they won't be disbursed, they'll be in specific areas where the socio-economic class can afford to purchase or participate in DER's and batteries, thank you.

MR. KATHAN: Pete?

MR. LANGBEIN: Great, Pete Langbein with PJM and thank you for the opportunity to participate today. Today in terms of participating in the wholesale market, really the DER's have two different avenues to actually get into the wholesale market.

One is through our normal interconnection process in terms of, you know, figuring out what the actual impact would be on the system and in that interconnection process depending on where they are going to hook up to the system.

All entities that would be involved or impacted are incorporated in that process to make sure the appropriate studies are done. The other avenues that DER's participates in today are in the world of DER where those resources are used to manage the load of that -- of that native customer.

So today it's one of two ways in the world of DER we do have provisions for aggregation that exists. The sole purpose for aggregation is an order for those resources to be able to participate because we have a 100KW threshold in order to participate in the wholesale market.

So it's not simply for convenience, it's in order to get enough scale to actually participate in the wholesale market than they are able to aggregate.

Any time there is aggregation there's a balance between control down to the, you know, a you know, a more precise level versus the ability for those resources to come into the market but therefore be more spread out obviously I believe some of this was covered on the panel yesterday.

So and from a distribution company role today our distribution companies are involved to the extent in the interconnection process that the DER is going to connect at a lower voltage level, it would be included in that loop because we want to ensure as my colleague mentioned that it's not going to create issues somewhere on the system by interconnecting.

So we would see the EDC's, we would continue to coordinate where that's, you know, needed. We also have coordination frankly on the DER side where we coordinate for data validity purposes and you know, we go through that process with the distribution companies today as well.

MR. KATHAN: Audrey?

MS. LEE: Thank you, thank you for the opportunity to speak today. I just wanted to introduce Sunrun briefly. Sunrun is the largest residential rooftop solar company in the U.S. We operate in 22 states, we have

180,000 customers today which was a growth of 34% on the year before.

We have over 1.2 gigawatts of rooftop solar deployed. But we also do have a residential battery product that we deploy with solar. We're seeing adoption rates of 20% in California for solar and 100% in Hawaii.

My role at Sunrun is to integrate our fleet of solar and battery resources into distribution and wholesale markets for the benefit of the grid.

I want to start out by saying that to the question our resources already comply with distribution utility interconnection requirements as Peter mentioned and so wholesale market participation activities would need to fall within those interconnection -- utility interconnection requirements anyway.

We do believe that the utilities role is at the point of interconnection and distribution utilities should only be allowed to prevent or delay DER's from enrolling in aggregations in the wholesale market if doing so would threaten the safe and reliable operation of the distribution system.

And so I think we need specific examples before creating any blanket rules about this and look at specific cases where there is a safety and reliability issue at hand and resolve those on a case by case basis. We certainly believe in information sharing, except we do think that allowing the distribution utility to serve as a gateway to DER participation in the wholesale markets, could put them at odds with DER interests in a way that would enable them to distort wholesale market clearing prices.

Utilities may also be incentivized to own their own DER's which potentially could create a conflict of interest with the customer sited or customer owned DER's in the same market. I think Commissioner Phillips remarked yesterday how D.C.'s retail market is wholly restructured which means in a state like D.C. utilities have no business deciding when behind the meter resources should or should not bid into markets.

I -- when I look at the questions I see them pitting the wholesale -- the RTO's and the distribution utilities, but not really talking about the role of aggregators. I think we have a very important role in sharing information and we can bring greater visibility to the system and you know, on the panels on data before this and it's not just distribution operators that can bring that additional visibility to transmission operators.

You know our solar plus storage systems do have revenue grade meters measuring the output of our inverters and then we also often have a shadow meter on the utility meter -- the retail meter as well. So we collect current voltage frequency, active power, reactive power, apparent power information at multiple points along the circuit where our customers are often with more visibility than the distribution utility who is measuring it at the substation or at various points where they have installed sensors.

And I just had -- I worry that we're letting the current rules in the system bias -- the current rules and the system that we have today bias our perspective and limit our scope of solutions so I just encourage you to think about how DER's can contribute to added transparency and information sharing and improving the system, thank you.

MR. KATHAN: David?

MR. OWENS: Well Audrey did a great job. I don't agree with a lot of what she said but I'm not going to take away that. So the question really is should we have an understanding of the aggregators -- the DER aggregators that would participate when the distribution system moved to the wholesale market.

As was mentioned earlier the utilities have the responsibility of safety and reliability at the distribution level. It was also pointed out how distinct the distribution system is. So I'm going to use the word visibility.

If you have the responsibility of maintaining reliability and safety, it's very important that you know --

understand the attributes of all those sources that are connected to the grid -- connected to the distribution system.

Not only is it important to understand the attributes, it's also important to understand how those sources will impact reliability and safety. And what does that mean? That means that as the utility you have to have some element of -- I won't use the word controls, but some element of knowledge of what those sources are doing in your system.

You have to have an understanding of how those sources will impact your overall distribution system -- how it will impact the flows on your system, how it will impact the attributes of voltage and frequency -- all of those are the responsibility of the distribution utility.

So just having a list and understanding the list of the aggregators is not significant. What is significant are the attributes of that aggregator, the attributes of that distributed resource. How that distributed resource impacts your overall distribution system.

And how in fact, you are able to ensure (microphone went dead) To me that's what the fundamental issue is. You -- as the distribution utility, having the understanding of all those sources that are connected to your distribution system, understanding all the attributes of that entity and ensuring that reliability and safety are maintained.

You need to understand the attributes of that source because to the degree that that source is disruptive to flows on the system is potentially disruptive to frequency and voltage and all the attributes of power quality, you , as the distribution utility need to be able to take action to preserve reliability and safety, so just having a list is not sufficient but having visibility, having knowledge, having coordination and having a say-so in how those facilities are operated are most important.

MR. KATHAN: Maria?

MS. ROBINSON: Maria Robinson from Advanced Energy Economy, we're a national trade association that represents advanced energy companies and for the purpose of this conversation I would say that we include DER providers and aggregators, DER folks, distributed wind and solar EV's and storage, just to provide you a little bit of perspective there.

I would say that I agree with Peter a fair amount in that the vast majority of this can be and should be worked out through the interconnection agreement with the distribution utility -- all of those folks that you mentioned in your question, the distribution utility, the DER aggregator -- all of them are involved as well as the

RTO.

And that's the moment in time where if there is a reliability concern as defined by the PUC, very clearly, then it would be identified at that point in the process and taken care of.

Now in talking about David's point around data what I think is important is that the RTO is receiving all of this data from the DER aggregator. It would use useful and also the most efficient if that RTO could then share the data with the distribution utility and that's actually something that could be written into the tariff as an obligation of participation is that you share the data from the DER aggregator to the RTO to the distribution utility and that way it would make it easier for the distribution utility because you're receiving it in a consistent format across all DER aggregators from the RTO.

So I think the order of operations there is ultimately going to be important to keep it both efficient as well as cost effective as the providers are looking at data points for tens of thousands of different rooftops having to do that already for the RTO and then having to then duplicate that again for the distribution utility would seem somewhat unreasonable as a part of that.

And I'll say -- and I know that we're having some folks from California talk about this process. I think we can learn from the California experience of what they've done around registration. Right now you have to register with the CPUC, with the distribution utility, with the RTO and in order to do that you need to get each and every one of your DER customers to sign-off in that registration and that can be difficult again if you're talking about tens of thousands of different customers to do that sign-off.

So making it so that there's automatic electronic registration in agreement as a part of that process -- I know that's something that the California folks had a proceeding on for several months just to allow for that electronic registration to happen, I think asking for that as a requirement would be very helpful.

MR. KATHAN: And Jeff?

MR. TAFT: So one of the words in this particular question that I think is significant, and you've heard references to it one way or another here, is the word "role". A lot of the work that we do has to deal with structure, of course, because its grid architecture work and that includes industry structure which includes automatically a definition of the roles and responsibilities of the various entities and organizations.

The differences that you heard in these discussions here actually reflect underlying differences in the presumption about what that structure looks like or it should look like.

When you go back a number of years, we started to see this issue about coordination back around 2011-2012 and we could see how this was developing in a sort of a de facto way into a situation that was going to result in these kinds of questions coming up.

When we first started talking about people thought we were kind of crazy but now coordination is a very common word, it wasn't very common back then. Understanding the roles and responsibilities of the organizations, understanding the structure -- the ways that those organizations are related to each other, actually gives you answers to these questions in a very straight-forward way.

When you attack the questions this way sort of bottom-up it's hard to sort them out because of the differences in presumed structure they're not actually being sort of explicitly laid out here.

But so, thinking about that architecturally gets you a way to get to these answers because, among other things, it defines where the interfaces are. The assumptions here were very different about where the interfaces are and therefore what the nature of the agreements would be necessary to have in order to make those interfaces work.

So what I would suggest is that one of the things you want to think about is, you know, the structure that we have developed essentially by organic means, may have limitations in it that want to be rectified before you can actually say this is the way these agreements should look and the way these interfaces should be.

So that's kind of a structural view and it always gets back to how are these things related to each other -- how do they interconnect? What does each one have to do and where are the responsibilities? Do they match the roles so that we're not asking the wrong organization to take on something or support it in a way that's not feasible for them?

MR. KATHAN: Commissioner Hall?

COMMISSIONER HALL: Thank you, good afternoon and I appreciate the opportunity to be here today. I mean it seems to me that there was 1, 2, 3, 4, 5, 6, 7, 8 of us here and we all said something that was consistent and that was yes, the utility -- the distribution utility, should have a role in determining when the DER should be able to participate.

And to the differences of opinion is -- is it through the interconnection agreement or is it through some kind of subsequent process and I don't know if I really care about that but what I do care a lot about is that before there is DER offered into the market that the utility does sign-off and I would also take it farther and say that I think that the state regulatory authority should as well, assure us that that new product is not going to cause any potential harm to the reliability and safety of the system.

And that is probably going to be my answer to every single question that we have on this panel. But I think it's absolutely critical that, that we assure reliability and safety and we also acknowledge that each distribution system is inherently different.

And the people who know that system best are the people on the ground which is the utility and then the utility's regulator.

MR. KATHAN: I think Jeff had his up first.

MR. TAFT: So one of the things that's interesting about DER in particular is that, you know, at low penetration levels you can do a lot of things that don't impact system operations reliability very much. And so when we started all of this we were at pretty low penetration levels and in some places in the country we still are.

At the bulk system level you see aggregations. In fact we talked about the aggregators here many times and so they don't see the same kind of volatility that you see as you move down to distribution. The closer you get to the edge, the distribution edge, the more you see the volatility caused by distributed energy resources.

And the problem is that that impacts reliability in ways that are pretty dynamic and so if you think about this and say, well, you know, I can stand back and look at it as a whole system impact, that's important but that's not sufficient.

So that's why I think you hear some of these different comments about how much we need to know and that's why I emphasize to understand the roles and responsibilities because not only are the distribution folks the ones who know their systems, they're the ones that are going to see that increased volatility at the edge which tends to be kind of masked at the system level by a sort of law of large numbers effect.

MR. KATHAN: Audrey?

MS. LEE: Yeah I was just going to respond to Chair Hall's comment. And I think we can agree to that except that I think that process should be very transparent. I think it should involve the aggregator, the aggregator should understand the exact situation and I would just mention in some of the previous panels when discussions in California and being able to map out the distribution system and understanding hosting capacity and local net benefits, you know, hold up San Diego Gas and Electric in California as having some great data publicly available on their distribution systems showing hourly loading of their distribution system and that helps the market understand where it can provide the best value to that distribution system at the same time as providing that value to the wholesale market at the same time.

So I just think that there's a transparency in process so that it doesn't get used against DER aggregators.

MR. KATHAN: And Mr. Crews?

MR. CREWS: Thank you, yeah I tend to agree that role is an important concept here because today I can't tell you what our role will be because it's -- we just, there is not -- it's not defined well so when it's not defined I try to make some definition of it and try to make it work in my head.

And so we're talking about selling into the wholesale market from a -- from a residential home with a battery, let's just take that for example. So we can argue whether that energy ever leaves the home or whether we need a distribution wheeling tariff to wheel it from the home up to the transmission level so it can be sold at LNP.

Regardless, we're going to need some sophisticated metering to do this because the meter that our distribution co-ops, and I told you we have 16, we have got 5 different meter packages or 5 different companies providing meters for our 16 cooperatives and I can assure you that each one of those companies have different models of meters and I don't have -- I've got multiple models from different companies on my system so I've got to figure out how to accommodate that.

And then I've got 3 accounting, 2 accounting softwares -- SEDC and NISC and then they've got multiple releases of that we're going to have to deal with. But there's going to have to be a settlement between the aggregators and the distribution company alright because the fact of the matter is when they turn those batteries on it's going to at least slow the meter down that we have delivering energy to that home if not delivering energy back to the system.

And a lot of my businesses talk to me colloquially but I've always been told you have to have control of the cash -- the cash box, alright. So we're not likely to give control of the cash box to anybody else. We will have a check meter as Audrey pointed out and then so we're going to have to take what was delivered, add it back to the meter for our retail because what was going to that home that was not displaced by the battery going back onto the system was a retail sale.

And then we've got to figure out how to settle with the aggregator on either how to credit the customer and I don't know whether they're expecting us to credit through our bill to the customer or if they're going to have a separate settlement with the customer -- I don't know today what they want us to do.

I can tell you that I'd rather than have a separate settlement with the customer because if there's something wrong with their settlement with the customer I don't want to be involved with the disruption of that settlement.

So there are a lot of roles that are not defined today about how we're going to do this. It's -- you know there are just a lot of things that are not defined and it's -- we're going to and there are a lot of different ways to do it and I'm not saying that it can't be done, but -- but there are a lot of stuff to be figured out.

MR. KATHAN: Mark?

MR. ESGUERRA: So I just want to kind of weigh in on a couple of things I heard. One it's in regard to our role and also in regards to complying with the interconnection agreement. I think I heard it mentioned that as long as the DER's complying with the interconnection agreement it should be fine.

While I agree under the low penetration type scenarios that that may be fine but as the penetration starts to increase and you start to have these aggregate resources that have a separate interconnection agreement, there's going to be potential gaps in terms of what is actually been studied in aggregate versus what has been studied individually.

For example, some of these DER's set the day for Pacific Gas and Electric. We connect about 4,000 net energy meter rooftop solar a month. We have roughly a three business day turnaround so we've identified ways of how to streamline that process in a very efficient manner.

What's going to get to a point when we start thinking about if these resources are going to aggregate and respond to wholesale market signals, does our current interconnection safety and reliability review process -- does it capture all of those elements?

And I think what we're starting to see is under low penetration scenarios maybe not -- but under when you start moving higher and higher we start to see some of the impacts such as voltage because clearly when we plan and designed a lot of these interconnections we didn't envision all of these resources now turning up and down at the same time to respond to a wholesale market -- that could actually create a safety and reliability impact on customers on the feeder.

The other -- the other item in terms of what we believe our role is in regards to coordination and ensuring safety and reliability of the grid. And the example I'd like to bring up would be maybe a future state, not too far, where there are potentially two different aggregators on a distribution feeder. Aggregator A is selling wholesale services to the ISO. Aggregator B is selling wholesale services to the distribution utility. If we're not careful, we're not mindful about being aware of what the aggregators are doing, we could run into a situation where there are potentially conflicts. Where aggregator A is asked to charge -- in California we have issues such as a duck curve and potentially the CAISO may ask them to actually charge and try to help a load go down.

But for the distribution utilities maybe that feeder is something that we actually want the demand to be down and we've enlisted the help of another aggregator -- aggregator B to actually discharge and to be able to put power back on to the grid.

And so if they're both firing at the same time you could have situation where none of the parties, the ISO or the utilities get the response we're looking for and that leads to an inefficient grid. And so even more reason why the utilities need to be more aware of what the aggregators are doing as well as what type of information is out there in terms of trying to coordinate their response to ensure we have an efficient, safe, reliable grid.

MR. KATHAN: Before I move to Audrey I just want to recognize that Chairman Chatterjee -- elevated to

Commissioner Chatterjee is here. Audrey?

MS. LEE: Thank you. I wanted to respond to David Crews' comments in terms of how exactly this will work. I think that's key is that we don't know and I think we need to allow the market to come up with competitive solutions to figure out how.

I mean it could be that as an aggregator that we use a wholesale forward capacity contract in order to finance a battery for a customer and reduce the upfront cost for that customer and that's where the revenues flow. Or it could be they flow directly where we share a portion of those revenues on a monthly basis with that customer.

And so I think we need to allow ourselves that flexibility and allow the market to come up with these solutions as we can. In terms of, you know, how they could be used I think we have to constantly ask ourselves whether we're prejudicing ourselves to the existing architecture of a large generator or power plant.

And we can't continue to think of us as a single -- single purpose assets and we can't think of DER's as equivalent to demand response -- they're different and that's where a lot of behind the meter DER's are awkwardly being forced into some markets.

And finally I think in a lot of the previous panels there was talk about non-dispatchable net energy metered solar which is very different than dispatchable storage that's charged by a NEM solar system so solar plus storage. And so there is multiple purpose and shared investments so you may have the customer paying for a portion of that, the aggregator paying for a portion of that investment through wholesale market participation or distribution participation.

And I think I can leave it until later, you know, discussing actual deployments of these and how these work I think along the lines of what Mark Esguerra was talking about -- I think it helps to talk about specific examples. So a NEM solar paired with a battery behind the meter, you could be compensated to charge for the solar mid-day because of the belly of the duck to reduced exports in California and the CAISO does have a stakeholder -- stakeholder process for that.

And then the batter could be scheduled to discharge in the afternoon whether load reducing or exporting from 3 to 6 p.m. because of a time of use tariff on the retail side. But then the very next day they could be discharged by the DSO to meet a distribution need and then the next day after that they can be discharged by the ISO for a transmission system need or an energy market need.

And then one day in the future all night long could be doing frequency regulation behind the meter. So I think the coordination part is very important but we -- but there's no reason so think that aggregators cannot sign contracts with utilities and ISOs at the same time and coordinate that and make that all possible.

MR. OWENS: So the question is should the aggregator have that responsibility or should the distribution utility have that responsibility? The aggregator does not have the responsibility of maintaining reliability and safety -- and so it does have that responsibility.

So I do agree with you about the broad array of functions that different distributive resources can provide which are very beneficial to the utility but someone has to have that responsibility of maintaining reliability safety.

Another way to say it is someone has to have the responsibility of looking at the total system or looking at all the distributive resources that are connected to that system and having some level of visibility and some level of coordination control over those resources.

Transparency is very important. It was pointed out that you can probably address many of these issues through the interconnection agreement and I disagree with that because the systems are evolving. The technologies are evolving. The infrastructures are evolving.

And so it's very, very important that the distribution utility not only had the ability to see the sources connected to its system, but also it had the ability to understand when those -- when those resources are aggregated and seeking to go to the wholesale market.

Utilities have to know about the implications of those resources that are aggregated moving to the wholesale market because of the impact on flows, because of the general role impact, most utility distribution systems are readily designed -- not like a transmission system which emits networks.

And so that means that you've got to see at all times what's occurring on your system. So while I agree with many of the points that you made, I think the fundamental issue is someone has to have the responsibility of looking at the total system, looking at the impacts of that total system of a distributive energy resource that's aggregated and moving to the wholesale market.

Interconnection agreements alone will not do it. Some technologies will not do it. There has to be the knowledge that the utility that was running the system is able to see that information and make cost effective decisions.

MR. KATHAN: Maria?

MS. ROBINSON: Thank you. I don't disagree with the idea that transparency is important. I think it was yesterday Chairman Hawke from Ohio actually framed this really well that the distribution utility should be considered a facilitator as opposed to a gatekeeper.

And I think from a DER aggregator's perspective they just want to ensure that the distribution utility is not serving as a gatekeeper and preventing the ability to enter markets. I mean we talked yesterday about how the ultimate goal of these two days and this whole conversation is to ultimately increase the participation of DER's on the grid overall and we want to make that as effective as possible.

Now I think there are a couple of different ways to potentially do this that would be efficient for both parties. One way would be for the distribution utility to identify specific zones that are able to take on additional DER's and say these are areas where we think that we can facilitate additional resources. I think another area would be if you do have the distribution utility ultimately have a review of this process that you limited to some relatively short period of time.

I know the gentlemen from PGE mentioned a three-day turnaround for interconnection. We were thinking something around 10 days for review in order to show significant cause for reliability concerns.

I think ultimately we just want to make sure that third parties are actually able to compete in the marketplace and aren't dealing with burdensome requirements that are uncompetitive.

MR. KATHAN: Let me actually do a follow-up you know, based on, and I'd like to hear other people's opinions on this is what Maria was just saying. A follow-up I was wanting to say is should there be a standard of review, a length of time as indicated by Maria in the RTO tariff or in rules for the distribution utility to have a chance to consent or to participate in the coordination.

I'd like to hear some comments on that, alright Peter?

MR. LANGBEIN: Great, there's an advantage to forgetting when you leave something up there. Yeah so one of my points I was going to make and I hear coming out loud and clear here clearly coordination is needed. You know when we go through the interconnection process any entity that would be impacted is involved. Maybe those studies, I think as Mark was pointing out , may evolve over time relative to the amount of penetration that there is and, you know, studies need to be handled maybe a little differently in the future than they have in the past.

You know, what I would think is that we would be able to get that done up from -- from market entry and then somebody's in the market and participating as opposed to something that iterates ongoing that we want to be able to establish a process up front.

That way when somebody's in the market they're there to compete against the other resources, you know, from a wholesale market standpoint.

MR. KATHAN: Mr. Crews?

MR. CREWS: The reason that you, Peter, was that he put his card up after I think I heard Audrey say that she would sell it to the ISO or the RTO one day and the distribution company to the next. Then my understanding is that most RTOs if you sell capacity you're obligated to sell to the RTO and you don't get to shop.

MS. LEE: I was talking about energy.

MR. CREWS: Even energy, if you sell the capacity you're obligated to have that energy to sell into the market is my understanding and I thought --

MS. LEE: That's if you bid -- if you bid that energy back Dave and not bid it another day.

MR. CREWS: In my opinion if you sell capacity you should have to behave in the market like the capacity resource and if I see and I do sell my capacity and then I have obligation to offer my energy into the market every day. So I don't have an opportunity to sell my energy to another entity when I participate in the PJM market and Peter, correct me if I go astray, but I'm obligated every day to sell my -- to have my energy ready to deliver into the market if I sold my capacity into the market.

And that's just -- I'll -- I don't think you get to shop when you sell your capacity into the market.

MR. KATHAN: Do you want to respond Audrey?

MS. LEE: Yeah just briefly. I think it's -- it's so complicated because in California there is no capacity market that lies with the distribution companies and there is an energy market in the CAISO and then in other markets in PJM and you -- obviously you can go in, there is a forward capacity market.

And so I think we just need to talk more specifics but I can wait my turn.

MR. KATHAN: Mark, I'd like to hear from you especially talk about the California process.

MR. ESGUERRA: So the California process in terms of DER aggregation -- so things that we're looking for is actually to evaluate these individual resources and things that we're checking for to understand if there isn't going to be any conflicts as I mentioned earlier.

A point that I wanted to make was in terms of should there be a timeline listed in the ISO/RTOs Tariff, and I think a timeline might be a little premature although I get it -- there has to be some certainty on their end and utilities are definitely motivated to move these interconnections along.

I think particularly for California, I think you've seen California really take a leadership approach in terms of streamline the process and I think we also want to take a similar approach but we don't want to get too far ahead of ourselves where we're compromising safety and reliability.

As I mentioned in my earlier points, these things are interconnected on a distribution grid which is highly re-configurable. We have many different points where it gets switched in and out so there may be multiple scenarios we may be required to look at and to try to get those studies done in three or I think I heard like a week and a half -- 10 days, could be a challenge without further sophistication in tools, more information, data, down the road to be able to help streamline and automate some of these processes.

So although I hear the question out there about should there be a timeline and I think that might be something that it might be premature to put out there but there definitely should be some indication of timeline or when high level response should be able to get back on this if it's feasible or not, or this will require more detailed study.

MR. KATHAN: Maria, I think you're card has been up.

MS. ROBINSON: So, again, to quote from yesterday Chairman Hawkins -- there are two types of barriers here that we're facing -- we're talking the distribution system barriers, the reliability barriers and then sort of marketplace policy choices. And that's why we have been talking mostly about having it as part of the interconnection agreement in order to give that -- give the distribution utility the opportunity to discuss the reliability concerns of joining the wholesale market at that point in time.

I think that is probably when it's most appropriate and most efficient for the aggregators in order to go through that process not multiple times with their customers but only through that one time and as part of that agreement I think to what Chairman Hall was saying, you know the PUC is involved in that process it's not as important to him sort of the specific timeline whether it's when the interconnection happens or when we join the wholesale market.

But I think allowing the opportunity to join the wholesale market should be just a given to these DER resources as they join the grid.

MR. KATHAN: I just have one follow-up question on that which is you refer to the interconnection -- that's at the initial interconnection the DER asset would be connecting. Are you saying that's the only time an interconnection or would there need to be one when the aggregation of several were put forth into the market?

MS. ROBINSON: I think we were talking specifically about the individual aggregation. I think the other appropriate time would be at the aggregate point -- Audrey I don't know if you have specific thoughts on that too.

MR. KATHAN: I know Jeff has had his card up for a while so I'm going to go to Jeff and then to Audrey.

MR. TAFT: So a lot of this discussion seems to sort of presume that this is kind of a one-time thing to say, you know, can this DER be connected? What information should be shared about it to decide if it's okay to connect?

But you should keep in mind that distribution systems are actually fairly dynamic in terms of configuration. So David mentioned, you know, that the feeders are radials but in fact in a lot of places they're interconnected in such a way that they act as radials but that radial configuration can be changed on a fairly short timeframe when in fact will change a lot in some cases.

I did some work with a utility some years ago that was a smallish company and they told me that on a quiet day they would have 100 or more switchings going on within to reconfigure feeders in their distribution system.

So that means that -- a DER resource today is connected on a particular feeder and go through substation A. A few minutes from now may actually be running through Substation B because there's been a reconfiguration of the feeder. So this -- this issue gets a little bit complicated as to where they can be allowed to operate and it's dynamic.

And the closer you get to the edge, the more volatility gets injected in the whole process here so to be careful not to say, well we should just have a couple of days for the distribution facility to say it's okay to connect it there -- it's a lot more complicated than that and sometimes it is not the same level of complication everywhere in every utility either.

MR. KATHAN: Audrey then I will go to Chairman Hall and then Mr. Crews.

MS. LEE: Yeah I wanted to offer an example of a case where there is a process for this and I think if the data shows that it is necessary, that we have gotten to a point where we need this coordination, CAISO Tariff Section 4.174 does give the distribution utilities a certain number of days to raise concerns with the proposed DER aggregation but I think it's important to note that the burden is on the distribution utility to raise the concern if there's a safety and reliability concern.

And then that the ISO -- the CAISO does make the final determination as to the eligibility. So, but the distribution utility does not act as a gateway as Maria mentioned -- mentioned earlier.

And just to respond quickly on Mr. Crew's comments -- the theme last night about multiple uses -- if you imagine 500 people at the front telecommuter today or on any given day and didn't come to work, does that alleviate congestion on the highways and parkways or does it alleviate congestion on the city streets, or on the Metro or in the FERC parking garage, or the FERC elevators or the FERC coffee machine?

And so, of course, those telecommuters provide a value to all those different places and so that service, you know, should be credited for all of that value. And you could take that a step further in terms of the coordination question of -- well if the FERC coffee machines are more free now you can create an app and tell your neighbors to come on over and use your coffee machines.

And so I think we can -- these are all problems that we can get over with better visibility and transparency as you say, but really keeping in mind that we want to add value to the system, provide more efficiency, reduce costs and reduce these burdens as we do that.

MR. KATHAN: Chairman Hall?

CHAIRMAN HALL: Thank you, so I mean I don't really want to get into the dichotomy between gatekeeper and facilitator because I think it's kind of false dichotomy. I do think though that the utility that knows the distribution system the best has to play a role in the process before there is aggregators linking up to the wholesale market.

And if there's concern that the utility is going to act unreasonably then it's -- I think all that's required is that you set forth very specific criteria to be applied when -- when making the determination as to whether or not registration should go forward.

That criteria could be set by -- could be set by FERC, it could be set by -- by the RTO in the tariff, it could be set, perhaps, by the state and reviewed by FERC. I'm not sure it really matters but as long as the criteria is clear and the utility applies it, I think that gets us beyond the gatekeeper facilitator dichotomy.

MR. KATHAN: Mr. Crews?

MR. CREWS: Thank you David. I'd like to point back to the kind of pass that Audrey and I had a minute ago. She was thinking about the California ISO and I, in turn, was thinking about PJM which you know, really points out the differences in the operating characteristics not only at the RTO level, much less at the distribution level.

And I apologize for that passing. But the other thing that needs to be considered in that venue is the penetration currently and California has a much higher penetration than say, Kentucky. And, you know, and there's no doubt potentially more need in California for some of this to happen than there is potentially in Kentucky.

Because our penetration of solar is modest and our penetration of batteries is even more modest and so for us to go through the administrative cost of developing tariffs or at this point is burdensome to potentially our other customers in Kentucky. And that's why I advocate that states should have the right to opt in and out of this because I think the Public Service Commission is -- is a good person to judge as to when it's time for a state to start offering tariffs.

When is there enough penetration of these assets within their service territory to start advocating for tariffs? I mean, you know, make no mistake, you know, given the diversity of metering packages and everything else, it's going to be an administrative burden for us and our members to accommodate that.

And when our members have enough of this out there that they want it, we'll do it. We're cooperative and we're owned by our members and when our members, you know, come to us and say this is what we want to do we accommodate them.

But the other thing that we have to be mindful about and I was talking to one of my NRACA folks earlier about the modulation levels here on the table with some of our soft-spoken, and I'm not problematic with that but we have had some folks that were soft-spoken and you can solve that problem right -- because you can have a different modulator for each one of these mics and everybody could hear -- hard of hearing people like me could hear.

You could solve these problems it's just a question of is it -- is the money spent worth solving the problem and I think I would advocate that that's why I think there's a good cause for the states to have a role in deciding when it's time to offer some of these programs.

MR. KATHAN: Maria and then Pete and I want to move on to the next question.

MS. ROBINSON: Sure. So I want to respond to Mr. Crews' comments there. Yesterday we had the conversation that this is extremely consumer driven and I believe the gentlemen from NERC earlier today said this is coming and we need to be prepared for it happening.

I know in addition to the types of companies that I mentioned earlier, we represent large corporate purchasers and they're really interested in this DER aggregation. Think about how many Walmart's there are across different areas and they all have solar panels on top of them.

And so I think this needs to be in place -- these tariffs need to be in place in order to allow that opportunity because the consumers are demanding it. You may not necessarily be hearing it directly from muni's and co-ops and the IOU's themselves, but the individual consumer is demanding it.

I wanted to concur with Chairman Hall's comments that there should be some very specific criteria set up for reliability purposes and I do think it still is a question of timing. Mr. Taft's comments said it's almost an ongoing review process.

But I think if that were to be the case there would need to be some serious process set up where there's a written affidavit from the IOU talking about what the reliability concerns are and then a review process that allows for appeal at the RTO level or even at FERC in order to question whether that reliability concern is actually real or not.

I think that if we're going to go in that direct there needs to be an appeals process in order to allow for a little less of the "gatekeeper role".

MR. KATHAN: Pete?

MR. LANGBEIN: Great, thanks David. I was just going to, you know, mention in the DER world where we do have DER that's just modifying load and I know that's a little different as Audrey said.

We've had quite a bit of success with aggregation, you know, and coordinating that aggregation across the various parties including the EDC. Again, the goal and the primary purpose of that aggregation is just to be able to participate -- to get enough mass to be able to participate.

So while the vast majority of resources that participate don't aggregate, we have been successful with the smaller ones to get them above that 100KW threshold so they can participate in the wholesale market -- be another resource to compete, another choice to be able to provide that wholesale service.

And I think as Chairman Hall mentioned, as long as that criteria can be clear of what would need to happen, you know, in that process, you know, to ensure safety and reliability then it seems like we may be able to extend a model like that in some form.

MR. KATHAN: Alright I'm going to move to the next question and this is moving away from the distributive role, but more to the question of coordination, and specifically are new processes and protocols needed to ensure coordination amongst DER aggregators, distribution utilities, RTOs, ISOs, during registration of new aggregations?

And we'll be talking about in the next panel about near real time but the question is does there need to be new protocol and processes and Mark, I'd like to turn to you specifically, because I know there's been efforts in California to try to develop that type of framework -- could you describe that please?

MR. ESGUERRA: Thank you, thank you. So there's been a lot of work on this in California. We put together information in a white paper under the more than smart TD interface white paper. And some of the things that came up we took some examples from demand response.

And so maybe just to take a step back. So the answer to the -- the high-level answer is yes, there will be a need as penetration increases to have additional new processes or protocols.

And one of the findings that we found was the three entities directly involved in DER participation and wholesale markets and this is around demand response -- pretty much the RTOs, ISO, the DO and the DER aggregator. One of the important observations that we've come today and this is maybe more California centric that can't speak for PJM in our other areas is that the ISO communicates directly with the utility transmission operator regarding the dispatch of the various utility -- non-market utility DR.

And the utility will manage the dispatch of these resources. Think of a future -- a high DER future. The coordination between the ISO and the TO will probably necessarily still remain but the ISO and the distribution company coordination on operational matters will require more direct communication.

And so something that we saw there is that today there isn't much direct communication between the ISO and the DO and it probably works right now to the current model but as you start to have these distributed resources participating, providing different services, there will probably be a bigger need for that.

The other finding is that the RTO and the ISO dispatching DER's without actually knowing the impact of what those dispatches are feasible or not on the distribution system. And then the other item here is more on the visibility side that currently right now in terms of DER participation and more for the ISOs, there's not really adequate methods to forecast how this DER participation can affect the net load and other important electric characteristics such as voltage at the TD interface.

And so something that you've heard throughout the rest of the panels is, you know, in terms of the distribution utilities and their visibility, we don't have the same level of visibility, control and situational awareness of DER's as our ISO, RTO counterparts have on transmission connected generators.

And what we're finding is that these changes will only increase as numbers of DER's increase and the different services and so it's necessary to start thinking about what are some of these processes to enhance not only the planning coordination which we talked about in terms of looking at an aggregate study, but as well as the operational coordination.

And so this -- we talked about this would require some review requirements assessing the impacts as well as the time tables all on how the utilities can turn that around. But we also understand that there could be regional differences in transmission and distribution systems around so that they might have different market framework and so consistency and clarity of the expectation to the extent that we could achieve it would benefit all parties.

And so something that we've been working on -- on a collaborative front is we have been, you know, the utilities have been working with the ISO's on mapping out what that interconnection process would look like in aggregate and really attaching timelines, how it fits with the ISO's timeline for interconnection and some of that requires also, you know, early consultation from the DER to reach out to the distribution utilities to start doing an early review in that.

One of the potential areas that we want to consider would be would there need to be some sort of coordination agreement or integration agreement of these aggregated resources which, you know, we're going to be going through this analysis to understand what are the implications, but there may be some operational requirements that may be needed and if there are potential distribution upgrades, you know, are there opportunities to give information early on to the aggregator?

So they may want to adjust their aggregation or they may want to site some of the resources in a non-congestion distribution feeder. So it's more than just applying, you know, distribution upgrades and other operational requirements but also providing early consultation to give feedback to the aggregators on what is possible.

MR. KATHAN: Chairman Hall?

CHAIRMAN HALL: Thank you. I think it is absolutely clear that there will be a need for new processes and protocols but what I would strongly advocate is that do not go to a one size fits all approach there. I think that the difference RTO to RTO are sufficiently significant that you should leave -- leave that to the RTO/ISO to develop through the stakeholder process and then submit a tariff for your review.

MR. KATHAN: David?

MR. OWENS: I thought Mark gave a real comprehensive answer and I'm just going to piggyback what he said. So my answer would be yes as well and I think I would say there needs to be coordination between the EDU and the distributive resource and perhaps you do that through some form of an integration agreement.

There needs to be coordination between the EDU, the transmission owner or operator, the EDU, the ISO and the RTO. So there needs to be complete coordination in my view. The reason why you want the coordination between the EDU and the distribution resource is as I mentioned earlier, because in a distribution system it's a system that's constantly changing -- for the most part it's a radial network.

You want to be able to coordinate with that distribution resource to the degree that there are limitations on some of your distribution facilities and the distributive resource needs to know that.

If the distributive resource is taking to participate in the wholesale market, you can give that distributive resource information that will help them make a better -- a better relationship -- a better involvement in the wholesale market.

You need the distribution resource, you need the utility to be able to communicate directly with the -- with the transmission operator as well as the ISO and the RTO because they're changing conditions that are always occurring on that utility system.

And you need to have some knowledge about the level of aggregation, DER aggregation that is seeking to participate in that wholesale market. You want to be able to understand that with your eyes open because there could be change circumstances that are existing on your distribution system.

So it's very, very important that you are coordinating well, that the distribution system's coordinating well with the ISO and the RTO and the transmission operator. So yes, I'm in agreement that there needs to be coordination agreements, but I would not limit that coordination agreement just involving the distribution utility and the RTO and the transmission owner -- there will also need to be the coordination and coordination agreement with the distributive resource.

MR. KATHAN: Audrey?

MS. LEE: Yeah I'll just reiterate that we -- we would agree with what Maria had talked about earlier about DER aggregations providing a lot of data into -- to the RTOI as a matter of participating in that market providing information anyway and then allowing the ISO to communicate that with the distribution operator rather than having too many complex flows of information in multiple directions keeping it simple.

MR. KATHAN: So a follow-up on that question which is, you know, we heard the need or the value of the coordination agreement. Are existing RTO/ISO procedures for communication and coordination flexibility enough, you know, to cover DER aggregration? Could they be scale to, you know, to DER aggregation at this point, Pete?

MR. LANGBEIN: Yeah, I think it depends on exactly what we're talking about and that will get down into the level of detail. I think, you know, Mark mentioned things like, you know, dispatch -- so today we have some -- we do have a form of -- we do coordinate, we do it in terms of who exactly is participating, who is in that aggregation, you know, a rough idea of the amount that will participate.

If, you know, and right now we are working with our stakeholders actively for those resources that want to actually -- that have capability beyond just managing their load of having them go through the interconnection process to make sure all the studies are done.

The question is going to be what other type of information needs to be coordinated and then how difficult is it going to be to do that? So today we are coordinating with quite a bit of the information but it really gets back into are we talking real time telemetries all coming in?

How does that get coordinated?

I'm sure we could work it out it's just a matter of figuring out what is it that needs to be coordinated, what has the value to ensure, you know, reliability and stability and that everyone's in the loop.

MR. KATHAN: Mark?

MR. ESGUERRA: Yeah so I'd like to answer that question but also provide a response to some other comments that I heard. So in regards to is there enough processor protocol right now and I'd say on the ISO/RTO tariffs, I'd say it works fine for in front of the meter-type resources. So I think we have a pretty good protocol so there are distributed energy resources that are in front of the meter that are participating -- I'd say the protocols work.

And something we've had some learnings over the last -- it took us, you know, almost 10 years working on demand response and really working out those protocols and it required actually a heavy collaboration with our state PUC's.

So when I take a step back and bring that in to this question I'd say going forward I don't know if it would be the utility should just go specifically to the RTO and ISO when you have a world of where these aggregators want to provide service not only wholesale, but as well as retail.

And so some of that information may be better with the distribution utility so just thinking about the coordination where that information should reside -- I think you know, there's probably multiple places but I think the distribution utilities would definitely want to understand how these resources that are particularly behind the meter, aggregated, and they're providing services for retail as well as wholesale and I feel like there's still some space to work there.

I think the coordination agreement concept that we've kind of discussed here is a good first start. There's a lot of other potential agreements that we've worked through like on demand response where we could leverage a lot of those learnings on how you actually establish, you know, that retail/aggregator relationship.

What are the obligations? What are the interfaces there for it to participate in wholesale? Really taking some of those learnings and as we start to build out this coordination agreement down the road as these aggregators start to look to provide multiple service and more than just demand response products, but wholesale and retail, I think a more comprehensive approach and not forgetting the lessons we've learned in the past.

MR. KATHAN: Mr. Crews?

MR. CREWS: Thank you David. Having just recently joined PJM, you know, I think back on that and when we joined PJM we gave functional control of our transmission system over to PJM because they -- they will be dispatching resources -- ours and others that will be moved across our transmission system.

And for them to do the dispatch to an economic -- least cost economic security constraint and dispatch, they needed control of our -- not only our generation resources but also of our transmission system so they could run all the studies to make sure that they were going to do it safely as well.

What we're talking about is a question here is do we have adequate integration of the distribution system to let the RTO dispatch DER and I would say probably not for some of the things that we've already talked about in that you're given functional control of what is essentially a generation resource to PJM but you're not giving them functional control of the distribution system and I would say it's not likely that our members would agree to give functional control of the distribution systems to PJM, which means we're going to have to have a high level of coordination between the distribution of the distribution operator and the transmission operator at PJM who is, you know, calling for those DER resources.

So that's -- that's the point I wanted to make.

MR. KATHAN: Marie I think you had your card up first.

MS. ROBINSON: I just wanted to quickly respond to Mark's comments and to clarify. I think the point that I was trying to make and I believe Audrey was also trying to make is that as long as there's an obvious pathway for the data to go, even if it additional data that you might need beyond what would typically be given to the RTO, as long as there isn't unnecessary duplication of the same data that may have to be in different formats for each individual EDC, you know, we're happy with that type of pathway and to make sure that the distribution utility gets the data that it needs.

We just don't want to have to give it in six different formats to six different EDC's when we're also providing it to the RTO in the required format for them as well.

MR. KATHAN: And Audrey?

MS. LEE: Yeah, I wanted to make the comment that I think I'm personally getting confused because the market rules are so different in different places and just separating California, which I am more familiar with where the utility with authorization from the Public Utilities Commission is authorized to procure capacity, the likely scenario though is that the distribution utility will be procuring capacity from DER aggregators and therefore dispatching those aggregators for both distribution need and system need as well.

But then other markets like ISO/New England where there is a forward capacity market where retail is de-regulated. You have passive capacity and it's -- there is a situation where the distribution utility will not have as much control over the asset.

So I haven't thought through exactly how things will evolve in a place like ISO New England versus California five years from now, but I think we need to take specific examples. I think we're getting a lot of input on the California side but I don't think we're getting the detailed scenarios for a place like ISO New England and what that looks like and look forward to learning more about actual scenarios for PJM as well.

MR. KATHAN: I'd like to move to another question which is what is the best approach for involving the retail regulatory authorities and the registration of DER aggregations in the RTO and ISO markets -- and I believe Chairman Hall it's a good question for you.

CHAIRMAN HALL: Thank you. Well I've alluded to this already but from my perspective I think that that -- the best way to involve the state regulatory authorities would be to allow the state Commissions to set the criteria for registration and then have the utilities apply that criteria when they're -- when aggregators are trying to get out of the system.

That criteria could be reviewed by FERC to make sure that it's reasonable. If there was an argument raised by an aggregator or a utility that could be appealed. I think through that process you have the state regulator that's the most familiar with the -- with the distribution systems within that state setting -- setting the criteria with an emphasis on reliability and safety.

MR. KATHAN: Audrey -- Audrey?

MS. LEE: If I understand what you just said Chairman Hall correctly, I wanted to make sure I didn't interpret that as the state having jurisdiction over participation in the ISO market and I think we should -- we could believe state jurisdiction over the distribution utility and participation of the DER in distribution services as opposed to getting into ISO.

CHAIRMAN HALL: Well I guess I would say at least in the short-term and at least in MISO the aggregation is going to be retail and wholesale in all likelihood. And so in that case I would say yes, that the state should be able to set that criteria.

MR. KATHAN: Pete?

MR. LANGBEIN: Yeah, I was just going to say the states are involved today in setting the interconnection criteria for things that come through the state level interconnection process but then that's coordinated through, for example, the wholesale market interconnection process.

That works for us today, we would envision that would work for us in the future if there are issues and modifications of course we will work with folks on that front. So, you know, it seems like that model, you know, has worked well and we would figure out what would need to involve in that model to kind of, you know, keep that, you know, working through.

The other note would be, you know, for the folks that have been purely just managing load, you know, behind the meter, we also have a process where we coordinate with the states, but we do that through the EDC's so we coordinate participation through the EDC's -- the EDC's, you know, interpret what the, you know, the state policy is.

And then that would have an impact on, you know, some of the participation requirements that seems like that's been pretty successful in the past, and you know, it seems like something we could leverage in the future.

MR. KATHAN: Mark?

MR. ESGUERRA: So similar to comments that were made yesterday. I think one of the other panels talked about in California Rule 24 around demand response and so I'm thinking here in terms of the best approach is I believe the retail regulatory authorities will have a critical role to play in establishing clear, consistent and transparency rules regarding mirroring or related mechanisms to ensure among other criteria, wholesale rate allocation for electricity we sold in the wholesale transactions and retail rate allocation for electricity used for retail rate arbitrage in the case of like behind the meter DER's.

MR. KATHAN: Thank you, Ray?

MR. PALMER: Yeah, hi, let's just move on to another question we're kind of running out of time but this is the last question on our program which is what types of grid architecture could support the integration of DER aggregations into the RTO/ISO markets knowing that a variety of good architecture is being explored in various regions, does it make sense for the Commission to consider specific architectural requirements for RTOs, ISO, for the effective integration and coordination of DER aggregation and I think probably we should start with Jeff Taft.

MR. TAFT: Yeah, this is something I spend a little bit of time on all day. When we first started to do grid architecture work for the DOE in 2014, one of the things we did was actually a survey of about 20 different proposed and existing architectures and schemes that largely had to do with integration of DER because that's where there was a lot of focus in changing things.

And when we think about architecture the architecture is in general -- system architecture is about the structure of things -- it's a high level view of how things are connected together and how they interact with each other.

We think of the grid in particular as a collection of structures. One of them is the electric infrastructure and although we hear a lot of references to it today you'll find people thinking about architectural approaches to DER integration and actually start to ignore that electric infrastructure.

It is never possible to actually ignore the electric infrastructure even though people start to forget about it and act as if it has either infinite capability or is somehow static -- it's neither of those things.

There's also an industry structure piece to this -- all these different entities that we've talked about in the ways that they're interconnected and then we get to coordination and control, communication, sensing and measurement -- all of those other things.

And something that we have worked a lot on that people don't always recognize as being a structure is what we call coordination framework. In a sense it's a mida-structure it's the way that all these things are able to work together to solve a common problem -- there's actually a basis for that in control theory.

The interesting thing about our utility industry in the U.S. is that there are places where the coordination of framework is quite explicit and easy to identify and see. There are some places where it's kind of hidden inside something else but it's there and there are places where it is flat out missing.

And the most obvious place where it's flat out missing is between system operators and distribution service providers. And the reason is that in the past it wasn't really necessary. And it didn't start to become necessary until we started to see the proliferation of DER and that we could see that DER would have an impact on the bulk system either inadvertently through the export of volatility or because people wanted to be able to use those resources to aid in bulk system operations.

But without that coordination framework piece, that sort of missing link that has led to all the kinds of problems that you are talking about today. So there are architectures that attempt to solve that problem by doing what we call grand central optimization -- let's get all of the data from everything all together in one place and solve this gigantic optimization problem and figure out all the dispatches and all the settings and put that all back out -- that's sort of one extreme.

And there are proponents for that kind of architecture. On the other extreme are extremely flat highly distributed approaches and we saw a lot of this in the RPE work a few years ago that says, you know everything is a peer of everything else and all we have to do is make sure that there's sufficient communication and information will flow and if we have the right kinds of rules all this stuff will work out and everything will balance and be stable.

And you can find papers that show mathematics that say that will be fine. But that doesn't take into account a lot of the issues that we talked about today like rules and responsibilities. If you have a highly flat diffuse system, people are going to become concerned about well who's responsible for reliability here if all of these pieces are just acting sort of independently.

So there are a range of architectures that fall in between and they recognize the fact that our electric system has a kind of structure built into it already and a really simplified way is sort of a three-tiered arrangement.

We have a bulk energy system, we have distribution systems and we have all of that stuff that's connected to the distribution level. It's more complicated than that but that's a rough picture of it.

That three layer model is a pretty important thing and we know from lots of other system experience that the value of a three layer model or more than three layer model is that the intermediate layers can help separate what goes on at the upper layers from the bottom layers and the sense of protecting them from bad effects.

So you should take advantage of that and think about that in these architectures and say you know what -- maybe there are roles and responsibility changes that need to occur especially for distribution and maybe those go along with changes in business model for distribution.

For the longest time distribution's business model has been to be a one-way delivery channel to break electricity from the bulk system to consumers and that's changed quite a bit. It's changed because of proliferation of DER and because of what people want to do.

So maybe that business model, maybe the roles and responsibilities change so that at the transmission distribution interface, instead of thinking of distribution as being essentially a load that flows from the transmission system, it starts to look more like a combination of load aggregation point and a generation tie point.

So that there's a bi-directional action there, and then it looks more like a peer to all of the other things that are connected and being sort of dealt with through the system operator. So some of the discussions that you are hearing about distribution system operator models and there are several models, are not so much about is there a need for a distribution level market for DER, that's almost a little bit of a side issue.

It's about how to coordinate between the distribution systems which are the inherent layer between the bulk system and the DER's and any system operator or balancing authority that would be responsible for the wider area there -- that's the discussion is about -- what should that set of roles and responsibilities be?

And one way to think about it is to say the distribution system operator comes to an agreement with the bulk system operator at that interface about the exchange of energy and services and then the distribution system operator manages all of those resources in its service area.

The aggregators have a tendency to want to say well do I want to operate directly into the wholesale markets? Well you can accommodate those things but what you have to remember, operationally you have to make sure that distribution reliability is maintained and safety and so on.

So you don't want to start creating arbitrary lines of connection that we started to see evolving back in the 2012 or plus timeframe. And we call that tier bypassing. So if you think of these three tiers I talked about -- if you start to have these things that go from the bulk system down to the edge and back up and bypass that middle tier, you create a lot of problems for the middle tier.

And you hear the folks who are in the middle tier here talking about that today. So creating a lot of ad hoc connections like that is sort of creating a kind of chaos and so the architectures that regularize that to sort of organize that by setting the roles and responsibilities and saying you know there is a layered kind of a structure that we can apply here, help clean all that up.

And in terms of what you might want to think about the Commission. I don't think it's so much a matter of saying that the Commission should try to develop an architecture and impose it on everybody -- I think that probably wouldn't work.

I think it is more a matter of thinking about these big structural issues of what do the roles and responsibilities look like and what are the major boundaries that ought to be laid out -- and when you think about that in terms of -- say if you look at California or New York, you know, the system operator service area is roughly consonant with the state.

So they have this ability to work with the state Commission, but when you look at the other ones that are multi-state, now you've got a different kind of a problem that those individual states all have to deal with the same system operator and vice-versa.

And so maybe some rough structural guidelines help all of that get resolved so that they can figure out individually what the best form of that actually is. So I would say the answer is you know, the architectures that are feasible and plausible are not at the extreme of highly centralized and highly distributed, they're more hybrid in between, they're probably multi-layer in nature and the Commission might want to think about, you know, some gentle guidelines in that direction, not trying to say well we're going to write a detailed architecture and say this is it for everybody.

MR. KATHAN: Thank you Jeff, I'll take comments from Mark and Audrey and then I know that Commission Chatterjee has a question so let's ask -- have these two comments and then we'll move to Commissioner Chatterjee's question.

MR. ESGUERRA: So this is Mark -- Mark Esguerra, so building off of what Jeff mentioned there and one of the points I mentioned earlier was that there was going to be a greater need to coordinate between the ISO/RTO and the distribution operator and I think that's something that as we get higher and higher penetration I think I'm hearing that message pretty clear in Jeff's message as well.

But as far as grid -- kind of what the grid needs itself in terms of a building us out -- I think there's this basic question about grid infrastructure, some foundational grid infrastructure that just needs to be deployed.

The distribution grid needs to be modernized to be able to accommodate this and we've talked about it in terms of providing additional hosting capacity, additional flexibility but we also heard the theme about additional system monitoring and management.

So additional grid visibility as well as visibility into the DER's to understand what's going on in that area. And once we have that data, you know, the distribution systems, the operator desk needs to be modernized in terms of some form of integrated grid platform.

There's going to be a lot of discussion about advanced distribution management and how do you bus all that information into some system that can automate and analyze a distribution grid in a fashion that is what the market is expecting?

MR. KATHAN: Audrey?

MS. LEE: Thank you, in the terms of architecture I think you know, we have two -- two pads ahead of us and I talked about our 20% adoption of storage and that's only growing for our customers. And given that technology costs are rapidly declining, especially for energy storage, and our residential customers are seeking rooftop solar combined with storage.

I think we can either go down one path where we deploy -- we sell all these batteries to customers, they're buying it for back-up during an outage. It gets utilized 1% of the time when there is an outage and 99% of the time it sits idle there.

And we will -- and then at the same time we will overbill generation and transmission because we are not utilizing these assets and that will be at great cost to customers.

Or we can take a second path and that path would be more of a sharing economy where we are maximizing the utilization of these deployed batteries across the system and today maybe aggregators, tomorrow it could be transactive energy and block chain ledgers in the future where we have a very flat system to do that, to dispatch these batteries for local and system need and reducing costs for all customers.

And so responding to Jeff's comments I would love for us to evolve to a DSO and for us to gain value to provide value with these -- provide value for the grid with these distributed energy resources.

I think what we do need though because that DSO model is not there yet, we do need wholesale market participation, access in the meantime in order for us to find value. But, you know, how it evolves, the architecture evolves -- as long as we can value assets appropriately I think we would love to participate in that, otherwise we are neutral on that.

MR. KATHAN: Thank you. Commissioner Chatterjee?

COMMISSIONER CHATTERJEE: Thank you and I want to start by thanking the staff and the panelists for what has been an excellent discussion. I just wanted to press a little bit further on the question of roles and specifically I have a question for my fellow Kentuckian Mr. Crews and anyone else who would like to respond.

You mentioned some concerns about ambiguity in the roles of the distribution utility -- the RTO and the aggregator, particularly for settlement. What's the best way to define those roles -- should we be left to work those out on a region by region basis or are you all looking for FERC to define those roles more clearly?

MR. CREWS: Thank you for the question Commissioner Chatterjee. You know I think settlement is definitely an important aspect of how we do it. The reason for doing it is to make efficient use of the assets and I do agree with Audrey on that -- that we want to utilize all the assets.

But we've got to have a settlement and while in my mind the way this works is that the -- the distribution company and the aggregator have a settlement that's separate and the aggregator pays the customer and we deal with the customer with regard to the services that we provide on our bill because for us to provide -- to have services that someone else provides in our settlement with the customer I see as problematic.

And I know it's potentially more complex than just having a credit go back to the end use customer through us for potentially for services that the aggregator provides. But that puts another burden on us and then the other thing is that when there are issues with the -- even if we do it the way I propose when there are issues we're likely to get the call because they see us as the energy provider.

But if we at least do it that way, then I can -- our member services folks can say here's that -- and we know who the aggregators are, we can say who's your aggregator, here's their number you need to call them and talk to them about your settlement that you're not happy with. I hope that was responsive to the question.

COMMISSIONER CHATTERJEE: It's helpful, thank you.

MR. KATHAN: Well thank you very much. This has been a great panel and I appreciate your time and we'll break for about 10-12 minutes and we will end the Conference with Panel 7.

(Break 3:05 p.m. - 3:19 p.m.)

MR. KATHAN: Alright so welcome back. We have finally reached the last panel and we've left the best for last. So we're going to be looking into what we talked about operational -- we talked about coordination issues in the past panel.

We're now going to go even to the issue of what happens -- what really is in the day, operating day or real time, how will DER aggregation work and how will the coordination happen. So we have a number of questions to try to dig into those questions, but before I go there I'd like to just remind everyone that we intend to focus this Conference on the technical and operational issues described in the notice.

We will not discuss other related matters including those at issue in any proceedings. And I also would like to recognize Commissioner LeFleur is joining us for this panel, thank you.

So why don't, in the interest of time, we just move on to the first question on the notice which is what real time data acquisition and communication technologies are currently in use to provide bulk power system operators the visibility in the distribution system?

And if you could also, as part of that, also do they provide adequate information to assess distribution systems in real time? So let's start with Gerald Gray from EPRI.

MR. GRAY: Thanks, glad to be here, Gerald Gray, Electric Power Research Institute, a non-profit organization organized for the public benefit. I -- after hearing my colleague, Dr. Taft, earlier answer the last question of the prior panel I sort of felt like my work here was done, but I'm going to labor on nonetheless.

I had thought this was an interesting question because in a certain regard we have transmission's data, we have distribution's data -- we can already pull that data in though often I know that there are utilities out there for example, distribution utilities, that don't have SKATA at all of their substations still.

But many utilities have put in AMI systems so there is a lot of granular visibility into what's happening in the distribution network and there's certainly those data acquisition capabilities and there's an ability to get that data around through other systems.

But -- so I think these capabilities are sort of well understood so I wanted to focus less on that and more on what we term distributed energy management systems. So they're aimed at addressing this need around data acquisition and communications capabilities to provide system operators with better visibility into the grid.

But first, as EPRI defines it, DERM's has four characteristics that -- it has an aggregation characteristic where it takes the services of many DER and presents them as a smaller, more manageable number of aggregated virtual resources.

And aggregation at various levels can occur for example in representing individual distribution district or a whole distribution system. The DERM's have to simplify the granular details of DER settings and present simple grid related services. Operators don't need or want to know the details of how to manage individual DER what the settings need to be passed.

They want to ask for capability for example -- say dispatch and have the DERM's handle that function on their behalf.

The DERM's have to optimize these DER within various groups to set the desired outcomes at minimal cost and maximum power quality. The DERMS has to pull in status and vet information from the individual DER and reliably forecast the capabilities that can be called upon.

And if managing a diverse set of DER, they should know how to best leverage the individual DER to get the specified outcome. This may involve equally spreading a request across an individual DER group or having an algorithm that determines how to best serve a request.

In translate -- an individual DER may speak different languages depending on their type and scale and the DERM's needs to handle these diverse protocols and present them to the upstream calling entity in a cohesive way.

So there are several field protocols that I think that we're aware of such as D&B3, 61 850, IEEE 20 50.5, Sunspect nodbus -- all of these need to be translated at the DERM's -- the DERM's can then use for example an ISC standard's based messaging for example, 61968-5 provides this enterprise communication that can go from the DERM's to a DMS or an EMS.

This one caveat is that control will need to be executed at many levels on the grid. This will require DERM's functionality to be distributed. We refer to it as a federated architecture approach.

And I think this echoes what Dr. Taft was referring to in the earlier panel about this coordination framework. We know that this -- he talked about the all central -- the Grand Central Station, or this flat -- everything has appeared to everything else. This goes back to the old battle that we used to hear from utilities.

And we think it should all be centralized and hear other stakeholders say we think it should all be decentralized and so on that question we get asked -- should it be centralized or decentralized? We say empathically yes.

And that's because there needs to be the coordination at these other levels as we walk through the other questions you're going to hear this federated architecture theme come up again and again at -- that there needs to be the ability to aggregate at different levels and communication coordination amongst these different levels, thank you.

MR. KATHAN: Thank you, I'm going to work down the panel this way and then come back to the people on the left, so Ali Ipakchi from OATI.

MR. IPAKCHI: Yeah, first of all thank you very much for giving me an opportunity to be on this panel. I want to follow-up with Gerald's comments. Certainly distribution SKATA has been used in distribution systems, however, it only typically goes down to probably the high-voltage circuits 12 KV, usually does not go down to where the DER's are at the end of the circuits at the end of the secondary distribution at the customer level.

So to provide grid services since we are talking about real time operations, offering services in real time often telemetry is needed. Often real time monitoring is needed. The point I want to make is that traditional telemetry that's used for SKATA systems using RTU's -- sorry, they really developed 20 years or 25 years ago in the industry, they may not be cost effective for DER's.

And also security and information privacy protection issues that have become very important in our industry may not be fully covered. That said, over the past 5 to 10 years, the information technology , communication technology, connectivity, cyber security has significantly advanced.

So looking at bringing real time data from distributed resources in a cost-effective, secure, well protected fashion in real time there are a lot of technologies now available which may not be the ones used, you know, in the transmission SKATA or traditional models.

So as we move forward with DER's I think some attention to -- first of all cost effectiveness, that's extremely important, but cyber security and information, privacy protection is also extremely important. However, the new technologies provide for all of those and I think there may be a need for as we look forward to 2020 and beyond, also embrace some of the newer technologies that have emerged and utilize those rather than looking at traditional models, thank you.

MR. KATHAN: Thank you, Lorenzo Kristov, Independent Consultant, formerly of the California ISO.

MR. KRISTOV: Thank you very much for inviting me to participate in this panel. It's really a pleasure to be here. It's an important event. I just want to start out with a couple of comments in response to your questions because really when I started at CAISO working with our distribution companies which Mark Esguerra talked about on the last panel.

We were talking about coordination between TND for high DER and we started pretty much from a clean slate. So there aren't really data acquisition and communication technologies that the bulk system -- at least in California, actually accesses and uses.

And similarly, there are not protocols for real time coordination between transmission and distribution -- it was never needed before. So we realized we were at the point of having to invent something new and that as we look across other states and other utilities that the starting point is very different for all of them in terms of what capabilities they have, what visibility they have into their own systems as well as what different state policy goals and objectives there may be.

So we set out to try and define what those basics might look like. And one observation that I think is important is that for the distribution utilities, they're going to need to do this grid modernization irrespective of DER participation in wholesale markets.

The fact that technologies are getting cheaper, ever more powerful, customers are adopting them is leading, I think, over the next several years to more and more a market for electric services being a behind the meter market and the grid playing more of a residual role which means the operational challenges for distribution companies are going to be novel, very interesting and demanding in terms of upgrading.

So I see that really as an objective that's going to play out pretty universally but at different rates because different states will experience different degrees of adoption, thank you.

MR. KATHAN: Thank you, Brandon Middaugh from Microsoft.

MS. MIDDAUGH: Thank you. Thank you for convening this session. Microsoft in this instance is both our technology solutions provider with our global platform offerings as well as an owner/operator of DER's at our data centers worldwide.

Like many of you here, we're seeing the rapid evolution of the power system caused by declining prices, technologic innovation and this is imposing new demands on the grid that require digitization and scalability.

We agree that currently there is very limited visibility of DER's to the RTO and ISO's. These are limited by telemetry, limitations on static data requirements as well as lack of deployment of real time communications.

As a result currently at the distribution level, a lot of capital expenditure as well as labor costs go into managing grid planning architecture in an on-site in-house -- in an in-house environment that's limited in terms of its scalability.

Our focus at Microsoft is on creating the enabling technologies to support the transformation. These technologies include the internet of things or IOT, machine learning, predictive analytics and cloud and edge computing that have emerged in recent years.

These new technologies will allow us to move the power system to the type of scalability that can accommodate the thousands and even millions of devices coming on to the grid for a more flexible and responsive system.

To get there requires not just the technical capabilities but also physical integration and market incentives to drive private capital investment in enabling dispatchable grid services.

I look forward to talking in a bit more detail about our experiences in piloting some of these technologies as we get into the rest of the questions, thank you.

MR. KATHAN: Thank you, Martin Ryan from NRG Energy?

MR. RYAN: Hello my name is Martin Ryan, I'm from NRG Energy and I want to thank you for allowing me to participate on this panel. NRG Energy feels this distributed energy resource is very important. We currently participate very heavily in this space and we look forward to expanding that participation in the future.

I agree with the gentlemen from OATI that what we really need to do is to communicate with these individual devices as cheaply as we possibly can. Currently what we do is not the similar way that you would communicate to a big large power plant.

We employ technologies that are much cheaper that go out to the individual pieces that go into our distributed energy management system and then we pass it to the wholesale system which allows us to communicate directly to the ISO's where we need to.

We're currently doing that right now in California, we do that in New England ISO, we do it in MISO and we could do it in any ISO that's out there -- ICCP to the ones that communicate via ICCP or with data concentrators or RTUs for the ISOs that communicate in that fashion.

MR. KATHAN: Joseph Ciabattoni from PJM?

MR. CHIABATTONI: Thank you, thanks for having me. Just -- you folks made a lot of good comments. PJM also uses a lot of the traditional technologies, RTUs, SKATA, ICCP communications -- but we also have explored newer technologies -- mostly from merchant plants that are more -- to make it more efficient and less costly for them to be able to communicate their data to PJM.

So I think there's some good points made in that area. We continue to explore these newer technologies as well. Currently today I think we can manage with low penetration of DER resources. We could manage using our current technology I think with higher penetration though we get into a situation where we would have to explore other -- either old medi in our current technology or explore other technologies that would allow us to manage a larger portfolio of DER resources.

MR. KATHAN: And Matthew Glasser from Consolidated Edison?

MR. GLASSER: Yes, so thank you for having me. Matt Glasser from Con Edison, also representing the Joint Utilities of New York State, that's 6 investor-owned utilities representing about 13 million customers.

So I'm from the utility's perspective -- from

Con-Ed's perspective in this case the communication and the visibility is not there for a bulk power system. They cannot see what's happening on the distribution system. So I think you heard a lot of different examples of the technology that, you know, could and should be there. It's not there today. And my overall message and we'll talk a little bit more about it later, but the overall message is we think it is critical as a joint utility in the New York State that if you are going to have DER aggregation at any level, and if you have DER on the system at any level, it needs to include the electric utility as part of that process -- the communication.

That process has to be with all parties, so thank you very much.

MR. KATHAN: Thank you, I guess we'll move on to the next question then which is a question on what processes and protocols do the distribution utilities transmission operators, DER's or DER aggregators use to coordinate with each other now and potentially what new processes would need to be developed in the future -- Matthew?

MR. GLASSER: Thank you. So I talked a little bit about the partnership and having to have electric utility as a part of the process. So currently we are starting to look at DER aggregation and the New York ISO is working on a pilot that will be starting along later this year to have DER aggregation testing it out trying to see how it would work.

Before going into that, although there wasn't -- you didn't have aggregation in the past, we drafted up procedures -- communication procedures and we drafted up like a registration and -- and agreement. The important part of that is that it establishes a baseline -- it establishes a baseline on how the communication will work.

Communication today with DER is low tech -- its phone and it's emails. Communication in our procedure will also be phone and emails but it's a base to start to build off of and to get us to the point where people know their roles and responsibilities and I think that's the key point that was something that was talked about earlier.

And on the registration side, the process we went through with stakeholder feedback is that again the utility, the transmission operator, the ISO and the DER aggregator have to be partnered together on a system, all understanding what their roles will be, all understanding what is going to be on the system and when and that's laid out with the information we collect from the registration.

So I think it's really important that everyone's working together on this and these are baselines -- these are starts. A pilot is just a way for us to see how it will work at this low penetration point and we expect to learn from it and build on that process for the future.

MR. KATHAN: Joe?

MR. CIABATTONI: Sure. So I echo some of what Matthew just said is that currently we're primarily using phone communication so it's a sort of top down approach where we're -- the RTO is talking to the transmission operator and the transmission operator is talking to the DER. Obviously for an RTO to better optimize energy and regulation resource we would need additional protocols and also the ability for the resources themselves to be able to follow base points and economic base points to optimize them electronically to kind of cut out some of that phone conversation and do these things a little more streamlined to the electronic signals.

MR. KATHAN: And Gerald?

MR. GRAY: Gerald Gray, EPRI. It's really interesting to hear the use of phone systems still and I'm originally from Michigan and we always used to say that the most effective demand response system was when we called up the GM Plating facility and told them to "knock it off."

So when we talk about DER aggregators and the aspect of this question it's the newest component and probably the least developed. Many companies presently managing large groups of DER are doing so for many non-utility purposes. For example they might be providing customer portals -- they may not be required to exchange information with the distribution or transmission utilities at all.

In our research work and methods for monitoring and control functions and protocols to address this interface, being addressed in IEC 61968-5 and this includes monitoring of aggregate -- what we term DER groups, reel and racked of power as well as dispatch and limiting of a number of parameters including real and reactive power and ramp rates for examples.

But I think it's -- when you talk about real time and those changes, the monitoring and control standards that are defined in these interfaces could theoretically operate at any speed right?

Operation in real time's whether that's seconds or minutes is not a question of the protocol necessarily but of the performance of the downstream communication systems used to reach the DER devices and/or meters that they're attached to.

A DERM's communication system would have to read the power output of every DER on the distribution circuit to produce a near aggregate reading for example. But if you have fiber to that smart inverter it's going to go at the speed of the fiber. If you have an RF mesh network that you're piggybacking from your AMI system, it's going to go at the speed of that and you're at PLC speed, why that's PLC speed but that's not a limitation of the protocol, it's a limitation of the communications in the structure.

MR. KATHAN: Ali?

MR. IPAKCHI: Yeah I want to make my comment -- address this for a particular segment of the industry. The co-ops and the generation of transmission GNT's. Many co-ops opt to be members of a GNT which typically manages 20 or larger number of co-ops.

And they basically provide services for the members in terms of a load management demand response or DER management for the benefit of their membership. The systems they use typically involve a centralized system at the GNT level which brings information for all the co-ops participating resources, parameters associated with those various programs or tariffs each member company has within their service territory.

And then the GNT basically aggregates those and dispatches those based on the rules and the agreements they have contracts they have with their members. This is somewhat similar to what Dr. Taft mentioned at the GNT level -- at the co-op level.

In other words, member companies each may have limited number of resources, limited number of staff, you know, more difficulty reaching out to the bulk power market or address transmission related issues, generation dispatch or things of that nature.

GNT serves that purpose for them. The provide the data to the GNT, GNT basically has dispatch access where they're directly dispatching the resources of the member companies or sending aggregated dispatch to the member company for it to relay it to its customers.

There are different models but that model of coordinating distributed resources at that level currently exists and has been fairly successful, thank you.

MR. KATHAN: Lorenzo?

MR. KRISTOV: I think it's useful to just talk a little bit about the perspectives or objectives of the three key parties we're talking about to understand what we need for effective coordination. We addressed this in the working groups we had in California -- the key players being the ISO, the distribution company and the DER provider and aggregator.

From the ISO's perspective if we have DER in the wholesale market what the ISO cares about is that when we issue a dispatch instruction we're going a predictable response with some confidence that we will see at the transmission distribution interface.

We're not really concerned about what individual DER may do at any moment because the ISO's responsibilities and its visibility is up to that interface -- so predictability and certainty about the ability of a resource to respond.

From the distribution utility's point of view, they've got to be concerned as we've heard several times with the reliable operation of their system. They've got the additional responsibility if they accept DER participation in wholesale market and they're facilitating that.

They've got to help make that work by essentially managing their system in a way that also supports DER participation and yet I think regulatorily they're all under a prime directive of serving load.

So that in a sense comes first in the way the regulatory construct is at present. From the DER provider perspective, they're looking for revenue opportunities about which they have some predictability themselves. And one aspect of the predictability of those revenues is how often might they be curtailed due to abnormal configurations on distribution?

We've also heard a few times that abnormal configuration circuit switching is much more volatile on distribution than it is on transmission. Right now there isn't really good information to give to potential DER providers about the frequency of particular circuits being taken out of service or being reconfigured, whereby it might be able to come up with statistical estimates of how often am I more likely to be curtailed?

There aren't procedures yet in place, there isn't a regulatory framework that says if there are multiple DER providers that depend on the same capacity -- what would be the distribution company's rules for how to allocate that capacity reduction among competing providers?

There's no open access kind of framework that's analogous to what we have on transmission. So I think as we think about what's needed to make all of this work -- those three perspectives are really equally important. They all have to be satisfied and then I'd go the next step and say the way that you work out the solution to those can vary a great deal depending on what is the model of the distribution utility, how they're thinking about their future, how they're thinking about their roles and responsibilities.

And this was a thought that I immediately leapt to yesterday when Commissioner LeFleur asked the question about why shouldn't we come up with the solution to solve the coordination problem here -- to figure out the best answer to it and then just propagate it?

And I think it's because -- at least one reason is because that question goes to the heart of the future utility business model. The distribution utilities are thinking about what do I want to be in this high DER world? I'm seeing revenues erode from the traditional per kilowatt hour ratemaking as people put on rooftop solar and they're buying fewer kilowatt hours.

And I think, you know, this is a discussion that's happening everywhere -- not even just in the United States, but all around the world is what will this -- how will this modernization play out. So I think , you know, it's those three perspectives have to be part of a wholesale participation model for DER and it will probably depend greatly on how the utility -- each individual utility views its evolution into the future, thank you.

MR. KATHAN: Brandon?

MS. MIDDAUGH: Thank you. So as we think about how to achieve those objectives, it helps me to frame it in terms of how do we get the data from our sensors, from our telemetry that's out in the field to the decision-makers and to the operators who need to rely on that real time data.

Because we are an owner-operator in the system today we have experienced both where communications stand today, the phone calls, essentially batch analysis and dispatch signals as well as in our pilots where we see where the industry needs to go in order to achieve the objectives that my co-panelists just highlighted.

For us, the way to get that data to the decision-making in a dynamic and iterative way -- on the last panel we heard a lot about the need for dynamic modeling and sophisticated tools -- for us it's too enable the devices that are out in the field to bring the data back using IP protocols that are very scalable and flexible and to have the type of interoperability, cross communications among different protocols so that it's not a barrier to communication based on what protocol and individual device it's on.

We've had some success in exploring exactly that model in a pilot in a European setting in Norway with a distribution utility called Okra Energy where we used IP enabled devices and real time computing to develop dispatch optimization algorithms so that the utility had the type of visibility to the DER's, the EV's on the system, residential PV, storage, you name it and had the ability to aggregate and process that -- develop insights quickly enough that they can act.

And so I think the point about timing is a very important one. What are we talking about when we say real time? The tools have evolved. They've evolved from batch analysis that, you know, needed to be hauled back to a central location, analyzed and then sent out on dispatch signals to the type of real time cloud computing as well as edge computing at the devices all the out at the edge of the grid that can enable not minutes response, but seconds and even fractions of a second.

And so I think we're seeing success in that and we believe that that's the type of obstacle that can be overcome and where we think it's worth putting a lot of attention is how do we get that to inform meaningful decisions that will affect, you know, the efficient operation of the markets, thank you.

MR. KATHAN: Doug Parker from Southern California Edison?

MR. PARKER: Thank you for -- I'll turn on the mic so my loud voice will carry even further. I guess I'm on the wrong panel because I didn't read this as a technology question. I read this as a business rules question.

I think Doctor Taft stole all of our thunder today. I think if you take away anything from the last few days, take away what he said because he really said it the best, I think. We're trying to solve a problem without defining the problem.

We talked about what is appropriate and adequate coordination, protocols, processes, communication, data exchange -- all of that stuff. You have to start with well what is the problem we're trying to solve?

And I think today it started to surface several times that we don't have operating frameworks between transmission operators and distribution system operators -- they don't happen. Maybe in the vertically integrated world -- I've been in the vertically integrated world for 20 years. ISO, just turned 20 years old last month -- everybody give a round of applause for ISO 20 years old.

Vertically disintegrated -- I'm not going to say that three times. The -- so we have to start with what's the problem we want to solve? And we have to start by asking what is that operating framework between -- I'm going to use the term DSL -- I think that's a loaded term but I'm going to use it anyway because that's what it says on my business card.

DSL and a TSO -- what is that operating framework? How do you define the systems and more importantly, how do we decide -- define the boundary conditions between the systems and how are we going to manage those boundary conditions?

If you can't answer that question than you can't talk about communication, data exchange technologies in an intelligent way. You can come up with answers and you can do stuff, but it won't be efficient, it won't be complete, it won't be consistent.

So we have to understand what these two entities

-- the aggregators and stuff I'll get to it in a minute but in terms of system operation, in terms of ensuring joint system reliability -- these are the two players -- the distribution operator and the transmission operator, collectively that makes the system.

All these other pieces -- generators, aggregators, load-serving entities, those are all parts of it but those two are the ones in charge of making sure it all works and hangs together. We have to understand how those two entities are going to split up the system and agree to coordinate -- agree to operate with each other.

From that operating framework, you can get -- you have to talk about roles, responsibilities and rules. You need to know the framework before you can talk about roles, responsibility and rules. And that's where you start talking about who's in charge of what, who's going to do what, when do things happen, how do things happen.

That is -- that's very important. There is when you also start talking about jurisdictional coordination comes into play. We do have two jurisdictions -- two regulatory jurisdictions that overlay this complete system. You've got the federal part on the transmission and we've got the state part on the distribution so there are rules, and responsibilities that have to cross jurisdiction boundaries as well -- that's going to make it more complicated.

From that coordination can now be discussed. How are we going to go in? Now what we know what people are supposed to do, who's in charge of what -- now we know how to coordinate. Now we know how to say, "Okay, I'm going to do this." We can start talking about decision hierarchy.

In the future world so far you've heard today a few times, there hasn't been a real pressing need for heavy coordination and heavy structure around coordination between transmission and distribution because quite frankly the systems don't bump into each other all that much. And when they do they pick up the flow.

And that's not an indictment on our inability to deploy technology, but it's really just a statement -- that's been the adequate and easiest solution until now. That's not going to be the case five years from now or ten years from now. Five years from now is next week, ten years from now is next month in regulatory space, we all know that.

So we have to start talking about this now. From those three you can now start talking about what kind of data do you need to share and what kind of data is important? Balancing authorities across the WEC don't know very much in real time. I'm talking about day-to-day real time operations. They don't know a whole heck of a lot about each other.

They don't sit there on the phone every morning and say, "Okay, what unit should I run and how much load do you have and my, what lines are you doing -- adding these on?" For the most part they have a very tightly defined boundary condition operating model and they have -- they know that that model ensures that if everybody plays their part, roles and responsibilities, it all works.

They don't need to know a lot about each other in order to make that work. So you have to understand battery conditions before you could say, "Well what data do I need to know about the other guy's system, and what does he need to know about my system and how often does he need to know that and how accurate, how granular?"

All those details flow from that. How we are managing this -- how we are splitting up the supply and managing it, who's in charge of what, how do we coordinate, now what do I need to know?

And then finally overlaying on all of that is markets. Markets are an enabling mechanism. It's the mechanisms we want to use to reach out and capture all the value of unused capacity that's been installed in the system and there's a ton of unused capacity that's installed in the system.

So we want to capture that. And that's what your

Conference the last two days has been about is here's another opportunity, there's a presumption of uncaptured value out there. How do we capture that? How do we capture that in this case in the wholesale market -- good question?

And I'm not suggesting that anything you've heard from me or in the last two days to say okay, stop the presses, let's go back to the drawing board and let's start with problem definition. You can make progress but I think my caution is many years ago we addressed this same problem with demand response integration into the markets. Now we're doing it with DER's. Now we're going to do it with batteries. And then we're going to start talking about other, whatever's next. I don't know what's next after batteries, who knows.

Okay, electric vehicles, micro grids, water heaters -- I don't know what's next, but they're all going to be -- at some point in the next five to ten year timeframe we're going to have to stitch all of this together. It's not a question of if we decide to establish this operating framework, it's a question of it's going to happen and there are choices, do we do it kind of from a let's design the house before we build the house perspective?

At least let's design the house as we're building the house but let's not draw up the plans after the house is built and now starting to fall apart.

And that's what I think we're at risk for if we don't keep in mind where this all goes in the future -- just my interest in all of this is that there's going to come a time and I think it hits California very soon -- maybe other parts of the country less soon, but soon enough -- that critical mass of DER's where at times during the year maybe half the load, maybe two-thirds of the load on our system -- on the Cal ISO system is being served by generators located on the distribution system.

The time is not very far off in the future so you've got these two entities have parody in terms of their responsibility in terms of the gravity of their decisions. It's not big transmission, little distribution anymore in terms of the impact on overall system reliability. They're a parody now very soon, so we have to get this operating framework established these roles, responsibilities, coordination, data exchange and then we can talk about overlaying markets.

That's the only reason I came here today so I've made all of my speech all in one time.

MR. KATHAN: Thank you, Martin?

MR. RYAN: Martin Ryan, NRG Energy. I think this is an exciting part of this piece. I've heard a common thread amongst all these panels that individual distribution providers can't see into their systems as much as they can -- as much as they'd like to.

A few of them really have some complicated and sophisticated SKATA systems to give them that data. We feel like we can go out to the customer with a cost-effective solution, pull the data that we need from the individual customers from all of these resources, pulled into our distributive energy resource system, pass it to the wholesale system, back to the RTO and then the distribution companies and get all that data right from the RTO for free without having to go and connect to thousands upon thousands of assets out in their system and immediately improve the visibility into their own system.

I think the technology's out there and it exists and we can provide that. You do that in a way that minimizes the cost of the individual customer and tries to help keep the barriers low as possible to get these customers to come in and participate in these programs.

MR. KATHAN: Alright thank you. I'm going to move to the next question which is about more focus on RTOs and ISOs. So what are the minimum set of specific RTO/ISO operational protocols, performance standards and market rules that should be adopted now to ensure operational control for DER aggregation participating in RTO/ISO markets?

MR. KRISTOV: Well there's a few things I could mention that I'm thinking about as just examples of what would facilitate the kind of -- a few things I'd mention as examples of what would facilitate the kind of coordination I'm talking about. So if I go back to the objective that I stated for the ISO. The ISO issues a dispatch instruction to a DER.

The DER responds. The ISO wants to know with some confidence that it's going to get back the amount of energy that it dispatched. Well, in the meantime or in some very short time period something can happen on distribution that now diminishes the ability of that DER to use all its capacity.

Who knows about that? Well the distribution company knows about that because they're the ones managing the system and they see when they switch circuits or have a problem. So one step could say, "Okay, if something happens on distribution and it happens on a circuit that effects this DER, the distribution company better let the DER provider know about that right away." Should the distribution company let the ISO know as well? Well we talked about that in our working group and said well, maybe it's better to put the responsibility on the DER provider because when we have generators in the market typically they have to report outages or D-rates in their capacity.

In the ISO market if there is a D-rate of a transmission line and that gets built into the network model right away and through the five minute dispatch it will be taken account of but you don't have that analogue.

So this notion of short-term immediate changes in conditions it reduces the capacity of the resource to be able to provide energy so when it's submitting bids in the future, it needs to take that in account or if it's got to respond 5, 10, 15 minutes from now, it submits a notice to the ISO.

These are kinds of things that we talk about that, you know, initially would be probably some sort of a manual communication and it might initially be very crude. In other words, if you're on the circuit and the circuit's abnormal, you're zero.

If you are an aggregated resource and all of your sub-resources are on this particular circuit and the circuit is abnormal, you're zero. If you're aggregated over multiple circuits and this one circuit is out, well then you've got the other two circuits so it's a partial D-rate.

But this is a crude first step at this kind of a coordination that works as long as we're thinking about relatively small numbers. Can it be automated? Well we haven't gotten that far because we sort of stopped in our working group effort when we realized that we needed more

DER providers to come forward and actually make use of the ISO's DERP market structure in order to bring real life cases that we could test.

But I think the point of this is to go back to some of the functions that need to take place and I think Doug characterized this really well that the answer to all of these things are done is going to depend on how the utility sees it's pathway into the future but there are standard functions that one can identify that need to be done as part of operating with a high DER system, operating with large numbers of DER's that want to participate in the wholesale market.

And it would be a good -- a very good use I think to be able to lay out what those functional requirements are and then think about where they naturally fall in ISO responsibilities, distributions company responsibilities, market participant responsibilities, thank you./

MR. KATHAN: Ali?

MR. IPAKCHI: I'm going to kind of answer this in a little bit of a broader fashion. You know following FERC Order 888 more than 20 years ago to allow transmission open access, to allow small independent power producers and market participants to come in and improve the economics of the supply and demand.

A number of processes, procedures, methods were established also let to creation of a structured market. And over the past 20 some odd years, a lot of lessons have been learned. Now what we are seeing happening on distribution side with the aggregators, the DER's, behind the meters assets, a number of things are emerging.

Certainly distribution is different than transmission and we are in a, you know, in a 21st Century and technology has moved et cetera. But some of the principles, some of the processes, some of the issues remain the same and the methods and things that were established for supporting the open access market-based operation on the bulk hour.

The number of lessons learned there that are to some extent conceptually applicable. For example, transmission reservation, capacity reservation, so am I investing in battery storage, significant investment and I want to sell that to the market. Do I have the capability to reserve capacity on the distribution system to be able for next summer and several years to be able to utilize that asset?

What's the process there? Similar to the transmission Oasis was created for transmission reservation. So when any independent producer built the power plant, could guarantee that they have access for transmission for exporting that generation.

Then there was reliability issues as these independent producers came about you got stuck having loop flows and you start having, you know, overloads on the system. So electronic tagging system came about to coordinate scheduling of resources with transmission operators and all the stakeholders that those schedules would impact -- a number of years it took to put processes and procedures and rules and responsibilities to be well-defined and accepted by the entire industry, who submits this schedule, who can approve it, who can deny it, who can adjust it, what timing for adjustment.

And then procedures for transmission load and relief, TLR's and curtailment and whatnot got established. So -- and the framework established that right now the marketplace at the bulk power is working very well.

So building upon all the discussion and then of course you have the ISO's which could be under the DSO's that they take certain role to do some of these functions but not all the regions covered by structured market and you're allowing, you know, a model, areas that are not under a structured market can operate.

So there are a lot of lessons learned from that process. I'm not suggesting we use the same technology, same capabilities that developed 20 years ago. Technology has advanced. Things work at the speed of light. Things are inexpensive, capability is available. However, some of the processes, some of the roles and responsibilities -- the processes and the roles and responsibilities to define why the stakeholders and that whole process -- there are some good lessons learned there that can be applied as we move forward and address this whole expansion of DER's and the changes -- paradigm change in the power system operations.

MR. KATHAN: Joe?

MR. CIABATTONI: Sure, I just had one issue that I think that we're working with DER in our stakeholder process today but it's the jurisdictional issues that were brought up by others as well.

You know, does DER have rights to deliver wholesale energy across the distribution system is kind of one thing that we would like to kind of nail down? I think once we kind of, you know, who would handle disputes, who resolves those disputes -- is it done at FERC, is it done under some of the interconnection agreement or operating agreement?

And then you know, from there we can build markets and you know, the markets may be more geographical based on how various RTOs are set up and that would allow them to organically grow as much as Ali pointed out, over time we sort of learn from our operations and kind of organically build on the system.

MR. KATHAN: And Gerald?

MR. GRAY: Gerald Gray, EPRI. Yeah, I struggled with this question in a certain regard because we talked about this volatility and the distributions which exist on the system but there is a recognition that next week, according to Doug, Doug's next week, that we need to have this different control at different layers in the grid that will need to occur, this hybrid architecture as Dr. Taft mentioned.

We call that the federated architecture with the control has to happen at different levels. When you talk about what additional protocols might be important for the future and if there should be minimum requirements that I kind of hesitated at that because even though I work in the standard space for example, and EPRI does work in lots of different standards areas and some of them are emerging like 61998-5 that I alluded to that can allow for some of these enterprise and business to business communications to occur.

That would certainly facilitate the future that we see that we're going to need very soon. What I would hesitate to be prescriptive in one regard and so I think that the market -- and I'm not talking about the energy market, I'm talking about the market at large in terms of technology adoption, what gets used.

What is sort of going to win is how any given technology protocol or technology has the characteristics to solve the problem that's in front of that person right? And I don't necessarily want to be prescriptive to that.

And just one example -- so for like IEEE 1547 it says that the local interface you can use three standards. It doesn't include for example, IC61850 which is in wide use in Europe and we've heard from some of our European colleagues that they sort of put a stake in the ground and it's 61850 from here forward, you know.

So TNP3, My Bus, those aren't part of the equation. You see other emerging frameworks like the open field message bus so I would hesitate to say at a minimum you have to do "X" with this technology that might prohibit new technologies to be tried in this space, thanks.

MR. KATHAN: Thank you. I want to now move on to the next question and this is -- it follows on from the discussion we had in the last panel and it's a question during the operating day, during the day head and real time dispatch, should distribution utilities be able to override RTO/ISO decisions regarding that dispatch to resolve local distribution issues and if so, should DER aggregations nevertheless be subject to non-deliverabilities under such circumstances -- Matthew?

MR. GLASSER: Thank you. So it was brought up in the previous panel and you know I don't want to think of the distribution system as this mystery that only the distribution utility knows what's happening and it could be switching at any minute.

But you know, people can envision a storm impact or loss of a feeder, whether it be a hit car or something like that and you have points where you'd be picking up and restoring customers with tie points. It may not happen but it could be the situation where you have -- there's a distribution resource or a distributed resource there that could help resolve that, that could help pick up load and keep customers in service.

This is where it's a coordination, so this is something that the discussion would have to be had with the ISO in saying, you know, here's where we need the resource and the ISO, where do they need it? Obviously the transmission system at the end of the day comes first but if it's something that they could work out, I think that's important and why this is a collaboration.

Utilizing the distribution system is a great opportunity for DER and aggregation. It's going to utilize the asset and it's better, it's efficient to be able to use that asset and it encourages people to install DER but you know, it's something that it has to be a coordination.

So I think it's a good opportunity to have that discussion. Whether or not that DER should be penalized I think I would say no, I think you'd leave that up to the ISO to make that decision. I don't know that that's the intent of penalizing them if they weren't available because they were being used by the distribution system, thank you.

MR. KATHAN: I'm going to go down the line, Gerald next?

MR. GRAY: Thank you. Yeah, we think that distribution utilities have to be able to originate to modify or limit DER controls in order to maintain distribution system reliability otherwise infrastructure damage can occur resulting in outages to consumers and a loss of the whole of the distributed resources in an affected area.

More granularly, when we talk about this federated architecture in the future if you have a local DER management system or distributed DMS as envisioned by this federated architecture, you should be able to override decisions based on local conditions.

We think that operations should follow a guiding principle of the controller closest to an issue should have the capability to respond as expeditiously as possible. I like to say latency matters and in the future if you have -- for example, DSO or distribution operator -- they're going to have a broader view of what's going on in the grid.

But if you have a local micro-grid controller or a local distributed DMS views its world -- you might send that thing in terms of the day ahead, for example, follow this ramp rate curve because we know what the bigger picture is.

But then something happens locally that intelligence that's closest to that situation should have the ability to act as quickly as possible to resolve that and then do event based notification.

And then central control can then update based on that new information instead of having the latency between something happening, getting that message all the way back and if you have a low latency or a high latency comes before the central control even gets that information, then they'd have to decide what to do about that information and now send a control signal and the other coordination that needs to occur.

The time matters. As to what penalties should occur, EPRI doesn't have an opinion of that as to what penalties should be put in place, thanks.

MR. KATHAN: Ali?

MR. IPAKCHI: A simple answer to your question is yes. There are a number of real liability issues on distribution as other panelists over the past day and a half have commented. Voltage issues, phasing balance issues, reverse flow issues, overload issues and with a higher penetration of DER's as we expect going forward, those problems are going to be more and more occurring. So the answer to it is yes.

However, that said rules for curtailments, rules for schedule adjustments needs to be formalized so the players know under what conditions their schedule, their, you know, ISO offering is going to be curtailed.

Again, like the comment I made earlier under transmission side the rules for curtailments are well defined. And so similar things are going to happen on the distribution side but the answer is yes, distribution system operator or distribution operator needs to be able to curtail transactions.

MR. KATHAN: Lorenzo?

MR. KRISTOV: I flipped it on, okay. I'll say it again, I agree with Ali.

MR. IPAKCHI: Even though you can't say that too much.

MR. KRISTOV: Yeah I know. I get a bit coin every time I do. Somebody had to say bit coin right? So it goes back to the objectives of the parties and especially a DER provider and that is transparency. I think one of the big concerns that we heard in several of the panels about -- about the distribution utility perhaps functioning as a gatekeeper is lack of transparency.

And the lack of an open-access framework analogous to what we have on transmission so that any curtailments are indeed the rules are transparent, all the participants feel like they're being treated fairly and there's some predictability as to how frequently these are likely to occur so that the DER who's trying to be a commercially successful operation has some knowledge of how should we build in expectations of being constrained into our business model.

So I think that that notion transparency setting up predictable rules and then of course, not being held accountable for things that are beyond their control. So I think I would lean on the side of them not being penalized if there are conditions beyond their control that make it impossible for them to deliver.

MR. KATHAN: Brandon?

MS. MIDDAUGH: I want to agree with Matthew's comments on this being the place where coordination in planning and in contingency response becomes really critical. From the -- from the perspective of a DER owner-operator, I think it would be critical not to have these conflicting signals than on their back on the owner-operator of the DER.

I think that there are numerous ways to overcome the coordination issue without setting the two up on a collision course in the case of the type of very real issues that could emerge at the distribution level.

Rather I think it's important to set out clear parameters up front of the sort that Ali and Lorenzo were mentioning, clear rules around when the wholesale signal would need to be modified or adopted to accommodate for distribution level issues.

MR. KATHAN: And Doug?

MR. PARKER: I beat you. I didn't get one word, I got two words out before I forgot to flip the switch. Several comments on this -- this topic here, I think there's three relevant points and that is there's -- the answer is yes, the distribution system operator is the one operating the system ultimately.

He's responsible for the reliability and security of the system, has to have a role in stepping in and saying no you can't. To that point the more often -- the better the upfront, the aggregation evaluation process, the more -- I won't say less often, because I don't think that's the right word but maybe perhaps the more predictable the circumstances under which the real time interruption or you can't fulfill your ISO instruction will be.

So we have to keep in balance there. We've heard comments that we don't want to burden some up-draw process and you heard DSO people say, "Well the less process you have here, the more real time consequences you're going to have here."

And that's just sort of a statement of fact. I don't think that's really debatable. The second thing is kind of the state of technology now is that on the distribution system we're still at the early phases of starting to modernize our grid.

And what does modernize the grid mean? That means when we're switching from a one-way flow to a dynamic two-way flow, we've got a lot more things we need to know about the grid and we just don't have the instrumentation out there yet to see it and even if we can see it we don't have the granularity of control to really segment off the problem spots and isolate those quickly and leave the rest of it unaffected.

We're figuring that out now. We're doing that now but it's going to take -- Edison's got 4300 circuits, it's going to take a while to get that kind of capability out there. So you wouldn't want to put rules out there that require a level coordination that cannot be supported by actual operating data.

And the third thing that is really I think related, it's maybe slightly off-topic but I think it's -- I think it's relevant is this idea that we're coming from a perspective of an industry that has been -- gotten really comfortable with knowing lots and lots and lots about a relatively few moving pieces of equipment.

And we're heading into a world where there's going to be lots and lots and lots of pieces of equipment that we just -- we cannot possibly know the same level of information about. And what that translates to me is -- is when we talk about data, we talk about coordination, we talk about these protocols and procedures that we need to put into place to get better at.

We need to accept that the world is changing, the piece parts that make up the power system and how it operates, and how it provides value are changing. And our operating strategies are going to have to change along with it. We can't stay at the exact same reliability standard -- I'm talking more at kind of distribution level now.

I'm not suggesting that NERC reliability standards need to go through a wholesale review, God help us if that ever happens. But we don't want to do that right now. What we want to do is talk about the idea that what constitutes the information you need to know in order to maintain a defined level of reliability it's going to change.

When you go from hundreds of generating resources to tens of thousands of generating resources, when you go from primarily transmission to distribution, what you can know, how variable it is, how it behaves is going to change. You know, operating strategies around that so that we can achieve whatever defines level of reliability. It's going to have to change with it. We can't just say we're going to keep our metrics the same and our standards the same and we're just going to outrun this problem with more and more and more data and more and more and more sophisticated analytics, that's not going to solve.

So it's a balancing equation. Again it gets back to we've got to know our operating strategies before we can really understand what level of data and communication it takes and the coordination it takes to support those strategies, an area of change.

MR. KATHAN: Thank you, Martin?

MR. RYAN: Martin Ryan, NRG Energy. The way we look at this question is that if the system is set up properly instead of having to override it and basically not perform a function that you were asked to perform, that you're going to be held accountable for through settlement is that it should suppress the deployment for the market award prior to you getting it.

If it's set up properly and you're approaching a limit, basically we'll curtail you similarly to the way you do transmission constraints on a transmission grid.

Obviously you can't burn the system down so if something happens, it doesn't work properly or something changes within the curiosity of when the market's running and you have an overload and there has to be some sort of an avoidable dispatch, we're going to comply with that avoidable dispatch, obviously you can't cause problems on the system.

But if it's set up properly you don't have to worry about the penalties, you just get an award that basically the system can support and you generate to that award and you're not causing a problem.

And we think that we should do that through the absolute minimal amount of rules and protocols that you have to put in place to maintain liability.

MR. KATHAN: Joe, did you have a comment?

MR. CIABATTONI: Sure, real quick. So yeah, I agree that they should be able to curtail resources issue. I agree with the coordination just as we coordinate with our transmission operators, there should be some coordination also with the EDC.

I think the thing to keep in scope here is that we want to make sure that there is not -- if it's fair and equitable, and we're reducing the right units, we're not doing it for the wrong reasons. I agree with Doug in the fact that if you set up your markets properly we should account for that.

Ideally we'd have some sort of LNP but I think we're very far from that. And then there's market rules that really should dictate when a unit is either made whole or maybe has to accept the responsibility of their commitment and whether they were able to perform to that or not.

So there may be things that are initiated. For instance, if we had manual control of units and there's no LNP to match that, then there's make hold provisions whereas if a -- say a unit is isolated because a line trips, they still have a day ahead obligation so I think market rules have to dictate whether they're compensated or not or penalized or not.

MR. KRISTOV: May I add a footnote to this conversation, thank you. I'm just as food for thought it's possible, it's conceivable that for a high-functioning DSO if an outage occurs where a particular resource has been given a dispatch by the ISO and it can't comply because of conditions on distribution that this high-functioning DSO could find other resources to dispatch as a substitute and still deliver what the ISO expected the TD interface.

That's a potential function to consider for the future.

MR. PALMER: Okay, here's another question. How might recent and expected technical advancements be used to enhance the coordination of DER aggregations? For example, integrating energy management systems -- EMS and distribution management systems -- DMS for efficient operational coordination?

MR. IPAKCHI: I think I want to make a comment that Gerald made at the beginning. The traditional EMS's and DMS's primarily looked at reliability of their wires. Dealing with DER's there are lots more detail in both commercial issues and others.

If EMS's and DMS's are expanded to include DER modeling and DER operations and things of that nature, yes, that would be helpful. However, they serve certain purposes. The staff that used them are trained to do certain activities. Going across the industry and having EMS and DMS's kind of come together, it is a major undertaking.

However, DERMS's come to play to basically focus on DER operations, DER modeling, model the distribution grid down to the secondary, down to the connection to the DER's, model the storage assets, model the scheduling functionalities needed, model the smart inverter capabilities that assets can provide reactive power and reactive power et cetera.

You know there is a -- there is a technologically architecturally from a technology architecture, the EMS's and DMS's kind of have been around for a number of years. Architecturally modifying them to address these things is not a small undertaking, so probably better answer is to augment the existing DMS and EMS's with the DERMS and integrate DERMS with those technologies.

MS. MIDDAUGH: Thank you. I think the answer to the question is in numerous ways as Ali pointed out, there are numerous trajectories along which you could see these enhancing the efficient operational coordination.

Some of the most important, from my perspective, are the learning and predictive capabilities of the analysis of the data coming out of these systems, and I think combining that -- merging that into the planning and operational process and having it inform meaningful decision-making and not just be a proliferation of data for data sake but having it really inform both planning and operations is the key to success on all of those trajectories really.

I think that capturing this data and using the tools that are available now for that learning and predictive value, that's where the insights will come from. But I also want to point out that the technology in its applications -- those aren't enough on their own.

I think it's very important to circle back to the fact that the market signal has to drive the appropriate level of investment in these to enable that to be a success, thank you.

MR. GLASSER: Thank you. So as far as the advancements and the technology that's available -- so today the distribution system -- we don't have a lot of that visibility down or that control. And we know that as we're moving along with our pilots, as we're moving along with improving communication that down in our future there'll be new technology, investments, training and a certain increase in the level of complexity of the details and the controls and the distribution system completely changing the way we operate the distribution system.

What we need to make sure we remember is that the way that that's paid for is through rate cases -- that's paid for by rate payers. So while really complex and detailed information systems and control systems are great but it has to be paid for by someone and that's rate payers so we really want to make sure that when we get there that it's the right level that we're getting the right level of control and visibility and technology, that we're not spending money on, you know, a gold plated system that customers are paying for, thank you.

MR. RYAN: Martin Ryan, NRG Energy. I think you have to be careful when you have multiple systems performing pricing on the system and dispatching on the system because what you do on the distribution system is going to affect the transmission system and then it's going to turn around and the transmission system is going to have to try and counteract what's going on there.

So having multiple systems I think -- I'm not so sure which one's more complicated whether you take the conventional system that we already have and model all the way down to the distribution system or if you try to figure out a way to make the two coordinate with each other.

But the important part is you have to properly set the price at all of these points all the way down to the distributed asset. And if you can do that then you get the proper dispatch and everything works the way it should.

MR. LUONG: I just had a follow-up question, you know regarding the distribution system that, you know, happening early that you cannot see the DER load and 12 KV you know, connected below that. So you know on the NERC Commission side they have a guideline to model it and now in the distribution side do you have any -- see any guideline, anything like that, for you to model it so you can see more.

Because you know, for the DMS you cannot even see it. So, you know, the EMS cannot see when the DMS doesn't have it. So on the distribution side do you have any guideline or any standard, anything like that to help people to model on the distribution side to model it, you know so you can see those things?

MR. GLASSER: So I'll answer to the extent I can. As far as modeling it's modeled, it's tested out to see to make sure that on the interconnection that the system can handle the generation as far as on any other kind of a model, like real time load flow models or things like that, not that I'm aware of on the distribution side.

MR. IPAKCHI: One of the important things in one of the very basics in dealing with edge devices -- DER's that are connected at the end of distribution lines is to have a proper topological modeling, connectivity modeling knowing where they are connected.

And depending on the utility, if there are advanced metering available so there is a, you know, granular load data at every single point at end of the line is available. Then calculating the flows on the lines is just a matter of basically you have a lot of data, but see you have data driven combined with topology to look at the flows on the lines.

Now you combine that with the DER operations and their schedules and their generation forecast and their conditions with respect to active power then you have a capability for looking at loadings on the lines.

With respective to reactive power, voltage levels, again, as we are moving forward sensing and communication, not the old model of putting RTUs, but sensing and communication has become fairly inexpensive.

So being able to have sensors on the lines certainly smart inverters, DER's that impact, they provide a lot of the information. Information available from those resources at the end of the line and if there's a concern but voltage levels are conditions further up the stream, upstream on the distribution side, some inexpensive sensors can also provide the information.

So the point is looking at the conditions with the conventional way of the grid power system done, especially with the transmission mind-setting mind -- as you are moving forward one has to start thinking about the newer technologies can be cost effectively, securely and in real time provide the information needed.

Now the industry may take a while for industry to really adopt those technologies but certainly capabilities are available. So short of detail, you know, mathematical modeling of every circuit, having topological connectivity, having data driven analysis it provides, you know, 90% -- solves 97% of the problem.

MR. GRAY: I thought it was interesting that both of these panelists talked about the need for models and one of the things that EPRI has a research program on working with different utilities on some of their modeling challenges, especially at the distribution grid.

Transmission models are pretty accurate -- why? They don't change that often right? The distribution models are always being changed and then as we see with the various big storms that come through then there's changes that get made to get the lights back on and then sometimes the models aren't updated.

One of the interesting things we see as utilities deploy smart meters and once they go beyond simple metering use cases and start using that data for other types of analytics, what do they find out -- often that the meters are located on different phases right?

The distribution utilities often have inaccurate modeling data. Data -- the modeling data exists and many distribution utilities have lots of different places and it doesn't necessarily agree with each other.

Now you throw in a DER going into different distribution locations and you try to run a power flow on a thing and it might work on your computer but it might not work in the field because stuff's connected on the wrong phase right? So having -- an earlier panelist talked about garbage in, garbage out. As an IT guy, I mean that situation has been around as long as computers right?

And that hasn't changed. So I think it is incumbent if you want to do all these things you really it's going to rest on having accurate models.

MR. LUONG: And just for a quick, you know, from every -- on the transmission side you have seam, you have you know, the common model information from the model, do you have anything like that for a DER for the distribution side?

MR. GRAY: Yeah, so the common and the common information model actually refers to the UMO model that's used for three different IEC standards. So there's 61970 which is for transmission -- that's the oldest one.

Then there was 61968 for distribution and 62325 is for energy markets. The common in that is you have these three families of IEC standards but the data model they use is -- what's the common in that common information model.

So DER is represented there, demand response is represented there, distribution assets are represented there as well.

MR. KATHAN: So I think our last question will be -- we asked this in the previous panel and I'll ask it here also. Is it possible for DER's or DER aggregations participating in the RTO/ISO markets in a wholesale level, to also be able to improve distribution system operations in reliability?

If so, please provide any examples of how this could be accomplished and Doug you had yours up first.

MR. PARKER: Thank you. I think yes, it's possible. It really goes to the objective function that was in play when the aggregation is set up. What's its main purpose? And if it's optimizing around capturing wholesale market revenues then that implies a certain collective set of customers that maybe collective set of locations based on what nodes are connecting to, you know, what ISO interface nodes.

And so it's just -- I think it's an empirical question how aligned would that business objective establishing that aggregation be with distributions circuit needs? And you've heard all sort of discussion about the variability of circuit needs and non-simultaneous, non-coincident needs.

And so I think it's -- it's something that has an appeal to it -- can you kill two birds with one stone -- maybe, maybe it's only one and half birds, maybe it's just one and a quarter birds, it really would be more of an empirical question than anything else so perhaps that is the question to tee up in that original aggregation evaluation process.

And say to what extent -- we have some -- we're not completely blind on the distribution system. We know lots of things and we know where our good circuits are, where our bad circuits are, we know where our weather tends to have more often impacts. We don't know yet where the car's going to hit the pole but that happens.

We do know a lot about the non-coincidence of needs on circuits. A big factor by the way in kind of a disconnect between wholesale market operations and distribution. You know, if you've got an ISO that's peaking or having peaked prices at 4 or 5 in the afternoon and you've got circuits that are peaking at 8 o'clock at night, you know, those aren't coincident needs.

So I think it's an empirical question more than anything else. I think it's not something that you can set out a rule that says, you know, here's how we're going to reconcile those two objectives because I think there's the practicality of where those customers are, what the objective of that resource was originally going in to build it and where it happens to be located on the distribution circuits matters.

MR. KATHAN: Thank you, Martin will be next and we're getting by on time so if people could be succinct in your responses it would be fantastic.

MR. RYAN: Yeah I think absolutely it could help and you put an aggregation together and try and get a larger set of assets together to participate in the market. You send the data up --there's no reason why you can't send the data up on an individual asset basis and the distributive operator sees that there's an asset on that line that needs help.

You could start the asset on a single basis and basically, you know, one of many on the aggregation that shouldn't be hard. We can control all of our assets individually and I think that should be something that would be very easy to do and you know, just compensate in them some sort of a cost plus basis so there's a margin there but you don't have offers in for the individual asset.

You have offers in for the aggregation but there should be no reason why you can't for reliability purposes start an individual asset as long as it's compensated.

MR. KATHAN: I'm going to move down this way, Brandon you're next.

MS. MIDDAUGH: Yes, thanks. I think the answer is yes and the thing I would point out is that you can either segregate in time non-coincident needs as Doug was saying or you can segregate in terms of the committed capacity.

And two quick examples that come to mind for this -- in one of our data center locations we are currently providing essentially distribution level support through back-up generating capacity, gas generating capacity. At the same time we're able to evaluate whether those same assets could non-coincidentally be put to work on the wholesale market as spinning reserve and so I think that's an example of time.

An example of segregating by committed capacity would be especially for energy storage, if you have a large battery system and are committing as we are in a partnership with PJM's advanced technology pilot program and with ETON, if you commit a portion of that battery to say the regulations or market following PJM's frequency regulations signal and reserve the remainder for distribution level needs that would be another example of a way to segregate by committed capacity, thanks.

MR. KATHAN: Lorenzo?

MR. KRISTOV: Yeah, I would -- I agree it is possible. I would just say that it points to this whole question of multi-use applications and some of the issues that have been mentioned about how to address them.

I know that there's workshops going on in California now sponsored by the PUC and they're taking up issues of measurement, dispatched priority, wholesale/retail issues when a resource is actually consuming energy from the grid to charge is it going to use that to offset retail load or is it going to use that for wholesale purpose?

These are measurement issues somewhat challenging to solve but not impossible. One thing I'd note is that between distribution services and wholesale services, there's conflicting needs usually regarding granularity of an aggregation that a distribution need is liable to be very local and if you have a large area aggregation while a distribution company is not going to dispatch whole large area aggregation to meet the needs of one circuit.

So some rules that allow you to say take apart that aggregated resource and use parts of it for a particular local function while the resource as a whole is serving the greater needs.

Some work that we did in the locational net benefits groups last year in California suggest that the biggest dollar value on distribution for DER may be offsetting distribution assets where they're substituting for a distribution upgrade.

So I think that may be a fruitful line of inquiry to see how can you configure devices that are offsetting a distribution need and then can they earn additional revenues in the wholesale market?

California ISO right now has an initiative looking at transmission assets on transmission for the same thing. Can they offset a transmission need and also be able to earn market revenues? So I think that's an area worth exploring.

MR. KATHAN: Ali?

MR. IPAKCHI: A simple answer yes. Example -- a resource providing reactive power which is voltage support which is highly valuable for distribution reliability while providing energy services to the wholesale. Those things can more or less be offered in a concurrent basis.

Reliability needs, distribution needs, types of products may be different than what the ISO/RTO energy products or capacity products are.

MR. KATHAN: Thank you and Gerald you have the last comment on this panel and last comment on the whole conference.

MR. GRAY: No pressure. I brought the bow tie power, no way. I did want to echo what a couple of these folks said so we would agree yes. And we talk about specifically IEEE 1547 and so this is complementary, it's not mutually exclusive as Ali said.

You could have a service for real power and reactive power running at the same time, they can run concurrently, simultaneously. We have talked about the challenge with DER, DER aggregations -- all throughout today's panels.

Lorenzo mentioned, you know, perhaps breaking apart the aggregations to a lower level and I don't know necessarily about that but what we would say is again what I would echo in the response to your earlier question that the decision-making needs to be pushed as close to where the issue is and so in his example if there's something that's happening on a particular circuit, whatever is controlling that local circuit needs to have the ability to make that effective change without having to deal with the latency of going all the way back to central control.

Now I'll cut my comments short there.

MR. KATHAN: Well thank you. I think this has been a very good panel, lots of good information and I am speaking for the staff in saying this has been a great two days and we've collected lots of great information, lots of good comments were made.

So we will be issuing in the near future a notice concerning post-Technical Conference comments so stay tuned for that and we'll have information, the procedures for timetables for those comments.

So with that I will adjourn the Conference and thank everyone for their participation.

(Whereupon at 4:53 p.m., the conference was adjourned.)

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This is to certify that the attached proceeding before the FEDERAL ENERGY REGULATORY COMMISSION in the Matter of:

Name of Proceeding: Distributed Energy Resources

Docket No.:

Place: Washington, D.C.

Date: Wednesday, April 11, 2018

were held as herein appears, and that this is the original transcript thereof for the file of the Federal Energy Regulatory Commission, and is a full correct transcription of the proceedings.

Larry Flowers

Official Reporter