UNITED STATES DEPARTMENT OF ENERGY

ELECTRICITY ADVISORY COMMITTEE MEETING

Arlington, Virginia

Thursday, March 17, 2016

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P R O C E E D I N G S

(1:00 p.m.)

CHAIRMAN COWART: Good afternoon. It's nice to see you all. This is a meeting of the Electricity Advisory Committee of the U.S. Department of Energy. And as most of you know --

(Discussion off the record.)

CHAIRMAN COWART: I'll start again. This is a meeting of the Electricity Advisory Committee of the U.S. Department of Energy. And as people here know, this is an official meeting that's being transcribed. The transcription will be available to the public and so it's important when we're speaking to turn on your mic and speak clearly. And when you're not speaking, to turn off your mic so that there will be less feedback. We hope we can get that under control.

As is customary for each of these meetings, there's a public comment period availability. And we have a sign-up sheet for any members of the public who are in attendance or who wish to come and speak to the Committee. And I

just want members of the public to be on notice that that public comment period is tomorrow at the end of the meeting and that they need to sign up in advance for that.

We should, I think, take a moment to go around the table and introduce ourselves. We don't see each other often enough, unfortunately, although a lot of you have been seeing each other quite often, I think, or at least on the telephone. There's been a lot of activity between meetings here and preparing the committee's work products and bringing the working groups together.

So I'll just start. I'm Richard Cowart from the Regulatory Assistance Project and chair of this Committee.

MS. HOFFMAN: Pat Hoffman, Assistant Secretary for the Office of Electricity Delivery and Energy Reliability.

MS. DALTON: I'm Liz Dalton. I'm Pat Hoffman's Deputy in the Office of Electricity.

MR. MEYER: David Meyer, Office of Electricity.

MR. ROSENBAUM: Hi. I'm Matt Rosenbaum. I'm the designated federal official of this EAC Committee.

MR. GLADDEN: Hi. I'm Devin Gladden and I'm a special advisor in OE's front office to Pat Hoffman and Liz Dalton.

MR. BALL: Billy Ball, Chief transmission officer at the Southern Company.

MR. SIOSHANSI: Ramteen Sioshansi at the Ohio State University.

MS. SILBERSTEIN: Pam Silberstein, NRECA. Welcome, everyone.

MR. THILLY: Roy Thilly, the tag says "Independent." (Laughter)

MS. CARMODY: Paula Carmody, People's Counsel for the Maryland Office of People's Counsel.

MR. ROBERTI: Paul Roberti from the Rhode Island Public Utilities Commission.

MR. CENTOLELLA: Paul Centolella with Paul Centolella and Associates and also spend part of my time as a senior consultant with Tabors

Caramanis and Rudkevich.

MR. VAN WELIE: Gordon Van Welie, ISO, New England.

MR. BOSE: Anjan Bose from Washington State University.

MS. BROWN: Marilyn Brown, a Brook Byers professor of sustainable system and a member of the Tennessee Valley Authority Board of Directors.

MS. SANDERS: Heather Sanders, Southern California Edison.

MR. GELLINGS: Clark Gellings, Independent.

(Laughter)

MS. CURRIE: Phyllis Currie, formerly with Pasadena Water and Power, now a member of the MISO Board.

MR. LAUBY: Mark Lauby, NERC.

MR. MORRIS: Jeff Morris, Washington State House of Representatives.

MR. MOUNT: Tim Mount, emeritus Professor at Cornell University, applied economics.

MR. ADAMS: John Adams, Electric Reliability Council of Texas.

MS. PRAMAGIORRE: Anne Pramagiorre from ConEd.

MR. BROWN: I'm Merwin Brown, the California Institute for Energy and Environment at the University of California Berkeley.

MR. REDER: Wanda Reder, S&C Electric Company, and I'm transitioning the chair for the Smart Grid Subcommittee to Paul Centolella.

MR. ZICHELLA: Carl Zichella with the Natural Resources Defense Council.

MR. POPOWSKY: Sonny Popowsky, formerly the Consumer Advocate of Pennsylvania and I'm the vice chair of the EAC Committee.

CHAIRMAN COWART: All right, thanks, everybody. Great to see you.

And, Pat, I think you're first on the agenda and we always look forward to hearing from you about your thoughts and what the Department's doing.

MS. HOFFMAN: Great, thanks a lot, Rich.

But first of all, Pam, thank you and NRECA for hosting the meeting. We always appreciate your willingness to allow us to host the meetings here, so I really sincerely appreciate that.

So a lot has been going on. I know that everybody's probably followed the Secretary in his daily running around, but he has been quite busy and quite active. Thus OE also has been quite busy and active. And so I thought I'd give you a little bit of a sense of my priorities and some of the things that OE is working on to give you food for thought for the next upcoming meetings for the EAC and things that you might want to contribute or provide some additional thoughts to the Department on.

So, first of all was mission innovation. As part of the Paris COP21, the Secretary announced mission innovation, which is basically a doubling of the applied R&D -- well, actually the near-applied, the higher risk applied R&D area to the clean energy technologies and investing in clean energy technologies. And so what the

Secretary did, the U.S., with 19 other countries, is maintain and affirm the commitment to doubling the R&D and really trying to get things to move forward. And so part of OE's budget is allocated to looking at how do we continue to support innovative technologies and advancing technologies in support of the clean energy mission.

And one of the things that was part of that was really looking at how do we get to some of this higher risk technology developments and get them over the hump. You can take whether it be energy storage or, you know, some other advanced technologies and say we need to really get this over the hump so it gets into the marketplace. So, not fully on the applied side, but on the higher risk environment, and so that is one of the topics in the discussions and things that we're thinking about in moving forward.

Now, parallel with that is what Bill Gates announced as part of the breakthrough energy coalition. And that side of it is really looking at more of the traditional venture capitalists and

investing in the future. And so that's one of the activities that we will continue to support as we're looking at doubling the clean energy technology R&D. It was part of that program.

I know that you will hear today about the Quadrennial Energy Review, but we are fully engaged in the second round of the QER. We call it QER 1.2 and that is focusing, of course, on the whole suite of electricity from generation to end use. But there are significant efforts that are part of that that we can discuss as part of the presentation, but OE is quite actively engaged in what some of the policies and the thought processes and an analytical baseline should be developed in support of recommendations that are coming out in the future. So that is also something that's pulling a lot on our radar and our attention and our resources.

The third effort, of course, is our whole activity across the Department, which is grid modernization. We've spent the time and really pulled together the Department of Energy to

have a consistent, cohesive grid modernization strategy. Likewise, we challenged the national laboratories to, as well, get value-added efforts pulling together from the national laboratory projects. You'll hear this, as well, in the updates today, but that has been a strong effort and really saying how do link these technologies that can be seen as somewhat disparate from what's being developed in EE or RB or OE, and really pull them together for additional value.

Part of that is also looking at the regional nature and the regional diversity and how we can continue to build projects that can start from where the regions are and continue to advance them in moving forward.

The third area that the Department is looking at that influences our work is international partnerships. The Department has been supporting a Clean Energy Ministerial. We will continue to support the Clean Energy Ministerial, which is a group of 23 major economies in the EU. And we usually host these

meetings that really go after commitment to clean energy. The next one is going to be in the U.S. in September. Right?

MS. DALTON: June.

MS. HOFFMAN: June, thank you, and so just to give everybody awareness that we'll be leading that.

Part of that and part of the QER is another activity that we'll be looking at as how do we strengthen the relationship with Canada and Mexico, but right now I'm going to probably focus on Canada just because the President met with the prime minister. And part of the Canadian announcement or the White House announcement was a joint strategy for securing the North American grid, and so I'm going to have to double down and think about how we can really cohesively take some points of common interest between U.S. and Canada in securing the grid and we'll, of course, work with NERC and the ESCC, the Electric Sector Coordinating Council, as part of the activities. When that came out I gave Jerry a call and the

ESCC was called to say let's make sure we do this collectively.

Some other things. So leading into the next statement is we are going to have a strong effort to really looking at our emergency response capability and our resilience activities in the Department and the projects we're working on. And we can get into that in further conversations as we move forward.

And the last topic is cybersecurity. I don't think we need to say too much but except to say this issue continues to grow. You know, you have what was in the news with respect to Ukraine. I think we need to concentrate our efforts and double down on our efforts with respect to cybersecurity and the efforts around that. I would say from a prevention and a mitigation point of view, but one of the things that I've been focusing on a lot is how do we think about recovery? And so that's something that we'll look at.

So the next activity or the next thing

that I would like to talk to you about is probably our budget and what's currently going on and just things that I'd like you to keep on your radar and think about from an EAC point of view.

One of the things that we are doing some follow-up work on is Aliso Canyon. And I know from the California folks the Aliso Canyon was, of course, a big topic with respect to gas storage and availability of gas, not only gas, but gas generation, plus the impact of potential reliability in the markets. I think this kind of feeds back from earlier conversations that the EAC has had writ large about the coordination of gas-electric interdependencies. I think this will continue to evolve, but just continue to be an important topic, especially with some of the dependence on the gas infrastructure.

So as we're moving forward, one of the things that we're thinking about is do we need to have a stronger dialogue around some of the availability of storage, gas storage systems out there, and the distribution and the correlation

with the electricity and electrical reliability. So that's one thing that we're thinking about near term or near-term type activity. And the Department wouldn't mind the EAC's thoughts. And if we want to do it, we could do a special panel session on that or a review, but I'd leave that up to the EAC, but it's a thought and a suggestion moving forward.

So now what I'd like to do is just give you a brief overview of our budget and where we're at from that perspective. The 2017 budget is a good moving forward for us. It's a $262 million budget request on the Hill. Our 2016 appropriations was very good, as well, that we for the first time had broken over $200 million in our appropriations. It was $206 million, so that's great. It shows the commitment to the grid modernization, commitment to investing in the electric infrastructure, and the activities. So we're going to continue to work really hard to do a lot of good things with that.

So some of our priorities in the 2017

budget and what we're doing with the 2016 budget, I want to give you a sense of what we're focusing on with our budget dollars. And all of this falls under the grid modernization strategy within the Department.

So the first thing that I want to talk about is energy storage. The 2017 budget has a significant increase in investment in energy storage. It's about $44.5 million. And what we really want to do is continue to focus on getting the cost down of energy storage, looking at some new energy storage materials and devices. But we also want to look at how do we push the institutional issues and the states issues so that we can get energy storage into the marketplace?

There has been different incentive-type programs that Washington State has done. There's the mandate program that California has done. But at the end of the day, I go back to the valuable reports that DOE and EAC have written, are ready on energy storage. And, of course, we're going to look at the distributed energy storage one

tomorrow.

But one of the things that we've got to think about is how are we going to capture those value streams for energy storage? I think that's still an Achilles' heel of getting energy storage into the marketplace. But, needless to say, we're going to try to continue to show I think the cost and benefit analysis around energy storage through the demonstration projects that we do through the safety testing and degradation and life cycle testing that we're going to do for energy storage. So that's one thing that I wanted to put on your radar.

The second thing that I'd like to -- from our budget point of view that we're trying to stimulate and move forward is increasing our partnership with the states. What we really would like to do is focus in on two areas that will support our partnership with the states. One is in the emergency response area, where we want to do regional exercises and really look at the impact to not only electricity, but the energy

paradigm in emergency situations. And so the 2017 budget includes a request for doing regional exercises and support of exercises with the states.

The second area is there is a lot of conversations that the states are having around the distribution system and what is the distribution system going to look like in the future from a structural -- I won't say not as much from a structural, but how that structure interfaces with the markets which interfaces with consumers which will allow the third party entrance to the field. And so one of the things that we would like to do is increase our technical assistance to the states, but actually organize it in a holistic fashion where we're supporting the conversation from a systems point of view, not just from a device or a generation point of view, but what does the system require. What do we do as we look at reliability at the distribution level down to the customer side and customer premise? What are some of the mechanisms where

cost recovery can be looked at?

And so that would be a partnership with the states that are interested in having the dialogue, where we could tap into the full suite of tools across the department to have an integrated approach of looking at the future. So those two are both state efforts that we're proposing in the 2017 budget that are significant efforts.

And I do want to point out that Devin, who is here, is going to be the point person for coordinating all these state efforts, so we can get everything organized and you can touch base with Devin later.

The third area was a new area that we were proposing in the 2017 budget, which is a grid institute. I'm not sure this Committee is familiar with it, but it's something maybe we can talk about in the future. Under the Office of Energy Efficiency and Renewable Energy there was a push with the Department to say how do we get manufacturing back in the United States? How can

we help build capabilities and jobs in the U.S.?

And so there was different -- even DOD has manufacturing institutes around power electronics. There's additive manufacturing that was done in partnership with Oak Ridge National Labs looking at new ways for 3D printing and additive manufacturing.

So we had proposed one on the grid institute. And one of the things that we were thinking about was as we start thinking about critical materials, critical devices, and domestic manufacturing that's needed in the U.S., is there an opportunity to develop an institute, develop a capability that would be U.S.-based and try to bring some of that manufacturing and some of that capability back to the U.S.?

So those were the three things, the couple things that I wanted to highlight as part of the budget that are significant new efforts that OE's trying to move forward, you know, depending on Congress and where things go. But at least it gets the message out of the importance of

the organization and the activities and the continued importance of investing in the grid space. So that's what I wanted to do.

Other than that, I guess the only other thing that I'd like to just give you a highlight on is I've been trying to do some roundtable discussions in the regions. I've been trying to do a couple CEO conversations really to take a pulse of the industry and what some of the challenges are and some of the current needs. And I don't think there is anything that's earth-shattering from those conversations, but it does highlight the importance of the dialogue in the industry, especially at looking at what are the business models for the future for the utilities, as well as what is the approach we should be taking from a cybersecurity point of view, as well as how do we look forward to becoming a platform where more technologies and more capabilities can be integrated on the system?

And so with that, I'm going to stop from there and that pretty much gives you a highlight.

And then, of course, we always can talk as part of the conversations of some of the other presentations for the rest of the agenda. So thank you.

CHAIRMAN COWART: Thanks, Pat. Are there immediate questions or comments on that for Pat? You don't need to be shy.

All right. We will get to it later. Next we have an update on the QER. We ready for that? Thank you. All right.

MS. BATTERSHELL: Good afternoon. Thanks for having me. My name's Carol Battershell. I work in DOE's Policy Team, so we've been working closely with the Office of Electricity on one of our recent projects and I expect that's why they wanted a bit of an update on this project. It's called the Quadrennial Energy Review.

We're just having a bit of a buildup of suspense while we try to find the slides. Anyway, I'll get going. I'll assume that they'll catch up with me.

So the Quadrennial Energy Review is a project that was directed by the President. There was a presidential memorandum saying you should look at energy policy issues. And that was back in, I think -- I can't remember the date of it, but about two years ago, and it was requested that we do a Quadrennial Energy Review. It sounds from its name like that might mean that we were going to do one every four years. Both the President and our Secretary decided we should actually break it up into more manageable pieces, so we've done one piece of that already, which I'll talk about briefly first, QER 1.1, and we're now working on a second Quadrennial Energy Review, or at least 1.2, which is primarily about electricity. The first one did touch on electricity, so I'll speak about that briefly and then I'll go into more detail on the second of these large policy reports which is predominantly about electricity.

Now, for those of you that might be familiar with this quadrennial process, and for those of you that aren't, it has often been in the

government a single agency issue, like they do a quadrennial defense review. That's just about DOD. One thing that's different about this policy study that I think is important for you to be aware of is this was directed to be a multiagency study. So in the first version of the report that we did there were 22 or so agencies involved. If you look at energy, even though we've got energy in our name, Department of Energy, certainly not everything about energy is managed within the DOE. So we had involvement from the EPA, from the Department of Interior, State, a number of different agencies. So that was the first one.

And the Department of Energy serves as what we're calling the secretariat. So they kind of do a lot of the coordinating and most of the analysis, but then there's a lengthy multiagency review process.

So the process in general, and this is a function, I believe, largely of our Secretary, a physicist and a strong believer in analysis, this is an analysis-based, analysis-grounded policy

review. So we commissioned, I don't know, 50, 60 independent analysis streams to support the first one and we also combed literature, looked at all the other analyses that were going on, and built those into the analysis, as well.

So that was there was a presidential memorandum. It's multiagency. Moving on to that it's analysis-grounded. So we have some documents that we're calling baselines, kind of looking at the state of play. It's largely a literature review, what's happening already, what's already known, what are the gaps. We do modeling and scenarios. We'll look at disruptive events. And it really is a lot of a synthesis of available work, finding out what the gaps are, and then moving forward.

We also have a big stakeholder engagement process. This is one of those types of engagements. We go out, we meet with a number of different people. We also have some formal public meetings. We've had one of those already in D.C. We had 14 various stakeholder meetings around the

country for the first QER.

So we have another process, which is about stakeholder engagement. And I mentioned before that it's a multiagency process, so we have a lot of collaboration with the other agencies. So those are kind of the three parts of the process overall.

Now, I mentioned for the first QER it has relevance on electricity, but it wasn't all about electricity. So the first one was on transmission, storage, and distribution infrastructure. Why did we do that first? It's because, you know, this is not going to be news to you, it's highly capital-intensive, it's very long-lived, it's kind of what connects all of the energy systems. And so decisions that are made now have long-lived impacts, so we thought that that was the right target to get on going on in the first QER.

We had multiple chapters in that QER. All of this is online. All you have to do is really search by QER and DOE. It's the first link

that will come up, but we had chapters on the resilience, reliability, safety, asset security, things about modernizing the electric grids, even the electric grid that was in the first one, as well, overall energy security infrastructure, things about how we integrate with North America, what are the impacts on the workforce or what are issues about the workforce that we should consider.

And then an area that I mentioned before this was heavily analysis-based. We came up with a couple issues that we weren't expecting at the beginning. So it really was not a what are our big policy ideas and then how do we have analysis that makes sure we get those in? It really was ground up analysis. And when we looked at all types of energy and how all of them move, we found some things about railroads and inland waterways and shipping oil and coal that we weren't expecting. Those are largely government managed and the maintenance is funded by the government, and so we had a separate chapter on what are the

issues related with shared transport? So that was the first QER.

And within that QER, and that's what the cover of it looks like, we had 63 different recommendations. And so right now we're busy both on the next QER, as well as implementing these recommendations. Not all of them related to electricity, so I'll move pretty quickly through this, but the recommendations -- this is important as context for the next QER -- is they are a wide range of recommendations. So some of them are executive actions, things that the DOE could do or that different agencies could do. Some of them are larger and harder to implement, like they would need additional legislation or they would need additional appropriations. And so as you know from how Washington works, those are a little trickier to implement, but they are on the list, as well. So we made a wide range of recommendations, some being additional studies that were needed, some were additional legislation that was needed.

The good news on the recommendations --

MS. HOFFMAN: We did have a presentation on kind of QER 1.1 and the recommendations.

MS. BATTERSHELL: Okay.

MS. HOFFMAN: And so I think the Committee's pretty familiar with that. Thank you.

MS. BATTERSHELL: Okay. So we're doing both the recommendations now, but working on the next one for scoping. So in QER 1.1 the things about electricity were changes in the generation mix, low, low growth, a number of vulnerability issues -- enough things about electricity that we felt the next QER should be on electricity overall. And the difference in the scope, if you look at the first QER, it was oil, gas, coal, electricity, but only the transmission, storage, and distribution, or if it's oil transportation, storage, and distribution. This QER for 1.2 is the full end-to-end, so we're both looking back again at transmission and distribution in the context of the full scale, but we're also adding in additional analysis on generation, as well as

end use.

And like I mentioned, we've got a lot of involvement from the Office of Electricity in that study. We're beginning to look through some of those analysis reports now that we've already started on. We had David Meyer in one of the groups. We were talking about our studies on valuation this morning. Liz Dalton was in one of the sessions where we were talking about how the studies were going on North American integration. So we're making some progress already.

So the QER 1.2 will analyze overall how the system is evolving. We're looking at how to integrate new technologies, the grid operations, changes in market conditions, financing, and how the consumer's role is changing. We're looking at the physical structures, as well as institutions. We're looking at issues like maintaining reliability, maintaining affordability, and also just the adaptation to the technologies and services.

And as I mentioned, we already have some

analyses with interim results. We're starting to look at those, but these analyses looks at things about the fuel choice, about centralized and decentralized. One of the studies that I've been working on is how is distributed energy generation impacting the distribution systems, so we're looking at issues like that, as well as things that you might expect, like physical and cyber vulnerabilities, federal, state, and those jurisdictional issues.

Again, this is a policy study, so while you hear typically from the Office of Electricity about technology issues that are going on and some policy, this one is predominantly a policy issue. And we're looking at business models, as well as the expectations of the consumers.

This is a little bit busy, but some of the main themes that you should be aware of and the timescale is that we worked already on scoping. That phase is completed. We're now in the analysis and moving into policy implications phase. I mentioned there are a number of these

baseline documents where we're trying to get the current state of play and some foundational analysis. We have one on generation, one on distribution, one on the markets and use; the environment, which has got components parts, some about greenhouse gases, but also ranging to issues like nuclear waste. And we have jurisdiction issues that we're just kicking that one off. So those are in multiple stages of completion. I've seen a couple drafts already of the distribution baseline; jurisdiction baseline just getting going.

So we will have that foundational analysis that will help inform us of what some of the analysis gaps are because these are largely literature reviews. We'll have a chance to kick off subsequent analysis to deal with that. And then we move into the phase where, grounded by that analysis, we look at what are the policy implications. What's going well, doesn't really need any federal intervention? Where are there issues that would benefit from policy? And then

we'd be, again, looking at what are the options that could deal with that and then what are some of the recommendations?

And that phase should be largely going on during the summer. And then, as I mentioned, it's a multiagency process, so there are at least a couple months dedicated in the schedule for getting all those different agencies to review the documents and get agreement.

And the red box at the bottom, that's probably the most important note on the screen, is the final report will be issued sometime between late November, early January. We're optimistically hoping for before the Christmas holidays, but that's the schedule that we're on and we will get this second volume of the Quadrennial Energy Report issued about by the end of the year.

Now, this is kind of the meat of it. These are somewhat busy slides, but I have made the slides available. And this is what I would encourage folks to take a look at when you get

time after the session. And if you'd like to submit comments, we have a place on the QER website where we take public input.

But one of the other grounding principles in how we do the analysis, we first start with foundational analysis. What's the state of play? But we also think about what policy questions are we actually trying to answer? What do we think some of the issues are?

And so what I have here is broken into -- it's 10 or 12 pieces with kind of a topic heading and then what are a subset. These aren't all the policy questions, but there are some examples for you, what kind of questions are we looking at in each of those. And I will just go through some of the example questions and then show you what the rest of the headings are and kind of leave you there with those are the issues that we're trying to tackle and this would, at this point, be a good place for people to input if they had comments. And, again, we've got a formal mechanism for that.

So one of the issues is about consumption and energy efficiency. This is the end use side of it. We're looking at a number of questions about what are the levels and patterns associated with not just electricity consumption now, but forecasted going forward by different sectors. And then that gives you an idea of what policy might be needed to deal with that.

We have a section on distributed energy resources, looking at demand response, distributed generation. We've got questions within that section about how should DER be valued? What are the valuation processes?

And we have a section of work on grid operations and planning. And the policy issues and questions that we're looking at in there include things like how do the different system architectures help or hurt putting in -- having efficient grid operations and introducing new technologies?

And then I'll just go through the other high-level titles so that you know the types of

areas that we're looking at. And, again, the slides are available, so you can look in more detail at the rest of the policy questions.

We're also looking at the generation portfolio, reliability issues, supply chain issues, the markets in which we sell electricity, the finance mechanisms, a detailed section on valuation. We're looking at innovation in technology, jurisdictions and regulations, as well as the environment. We return to the topic that we touched on in QER 1.1 about resilience. We're also looking at physical and cybersecurity. Once again, we're looking at integration along our borders with both Canada and Mexico, and we're looking again at workforce issues.

So we've got policy issues within each of those categories and that's what we're focusing the range of analysis on and that's what we're likely to have policy recommendations on. Again, by the end of the calendar year we'll have a public report. And we've got a series of meetings where we have Federal Register notices about when

those are coming out, and would encourage people in the regions to contribute to those, as well.

CHAIRMAN COWART: Thank you very much. Are there questions or comments from Committee members? Merwin?

MR. BROWN: Merwin Brown, CIEE. To me, there are at least two factors that have quite a bit of ambiguity in looking at the future and I was going to ask if you see this the same way and whether or not you've made decisions on this. One of them has to do with distributed generation. When you're looking at the generation focus as one of your bullets up there, you could include distributed generation along with central generation and look at it as a sum total of providing electric supply. Or the other way to look at distributed generation as a negative load, which means how does that influence load modeling? The former one would be generation modeling. So there you've got an ambiguity of how to treat those two and so that's one question I pose.

And then the similar question in some

ways has to do with energy storage, although it's a little more difficult to look at this. Energy storage on one hand could be looked at as just a substitute for other kinds of grid elements that are out there, such as generation or various grid control systems, power quality systems, et cetera. Or it could be looked at as a paradigm-changing technology if you look at it in the context that for the first time the delivery system will have the potential ability for warehousing the product, which up till now has not been a substantial part of how you would treat that technology.

So those are two items that would, to me, pose a sticky issue of how to treat them going forward or how you treat them both ways, which makes your work harder.

MS. BATTERSHELL: So we think that we've got a number of challenging issues. You do a good job of explaining a couple of those.

On the generation one, and I guess it doesn't come out as much as I hoped it would in the presentation, but one of the things that we

try to do is look at things from multiple perspectives. So we have a generation group and they are looking at distributed generation as a generation technology, so we're looking at it from that perspective. We also have an end use group and they did a baseline study, and they included distributed generation as exactly you identified as a way to also explain how demand is changing.

So we're looking at it from both perspectives. And we have these groups that are set up and what we find is everything is intersecting. It's hard to have any of these issues which are completely isolated, which is why we set up cross-cutting groups and which is why we bring as many perspectives into it as possible, both analysts from the policy team, analysts from the technology teams, like the Office of Electricity. We also have the Energy Efficiency Renewable Energy Office contributing. Where we have issues about generation that are related to nuclear fossil, we have the fossil and the nuclear offices involved. And we look at all the

different departments, as well. So we're trying to look at it from as many perspectives as possible.

And on your storage question, that one sits mainly within our grid operations and planning team that are looking at that, so we are considering storage as an issue that has relationships and impacts on how you operate the grid.

MR. ZICHELLA: Hi.

CHAIRMAN COWART: Clark and then Carl.

MR. ZICHELLA: Oh, I'm sorry. Go ahead, Clark.

MR. GELLINGS: My apologies, Carl. I think you're getting to this, but I wonder, you know, forever our view -- that is "our view" being the view of our system engineers -- has been, well, we generate and then we find a way to get it to customers and they consume it. But, you know, I think we are getting to the point where we might begin to consider turning that completely around and when we have discussions about the technology

issues surrounding electricity we start with the consumers and we start with the idea that they need energy and that energy can be supplied in a number of ways by a number of systems, among those happen to be what now is the most dominant system. But as we look towards the future, some years out, that may no longer be the case. Just a thought.

MS. BATTERSHELL: It's a good thought. One of the things that sticks with me on that topic, and, again, we look at a lot of literature, is EPRI had -- I think it was EPRI had a good chart on the grid as it used to be with, you know, a single line of power moving through the system with a pretty straightforward system. And their new one is a ring with lots of arrows going multi-directions for everything. And that, I think, kind of --

MS. HOFFMAN: I paid her to say that.

(Laughter)

MR. GELLINGS: I think I sketched it. I didn't draw it. We have an artist to draw it.

(Laughter)

MS. BATTERSHELL: Okay, well.

MR. ZICHELLA: Carl Zichella with NRDC. This is an easier one, I think. Just thinking about the mechanics of how you're going to do the stakeholder work, first of all, I thought the Department did a really good job in 1.1 and the stakeholder workshops. And they broke out a number of different topics for different locations. I presume that'll be the same method. And have you thought about sort of how you're going to break out this list of topics that you've just described for us for the stakeholder workshops?

MS. BATTERSHELL: So some relationship to how it was done in the last one, but a slight nuance and not positive I'm going to get this all right, but it's something like this. There's going to be, I think, three panels in all of the sessions. And because there's a huge regional variation, which you guys know better than I do, we are having I think it's a generation and transmission, distribution and end use -- those

are two -- panels at each and every one of the regional meetings, plus a third one which is a special topic that has to do with that regional. But we think the regional issues are big enough that we will want to talk about generation and transmission, and distribution and end use in each and every region that we visit. But we also think these topics are important and so we're trying to meld those two together.

CHAIRMAN COWART: Any other questions, comments? Yes, Billy.

MR. BALL: This is actually, I guess, a follow-up to Carl's question and to your answer. On the third panel, in each of the regions is there process for determining what those special topics might be?

MS. BATTERSHELL: There probably is --

MR. BALL: Okay.

MS. BATTERSHELL: -- but I don't know what it is. Sorry.

MS. HOFFMAN: Do you have a specific interest?

MR. BALL: No, I was just curious.

CHAIRMAN COWART: If we can't answer that question in this meeting, in other words, find out who's organizing and deciding, that would surprise me.

MS. BATTERSHELL: So there is a process. I don't know what it is and it's not my process. What I do know is that they will be announcing all of those meetings, the dates, the locations, and the topics for panels in the Federal Register very soon.

MS. BROWN: Marilyn Brown, Georgia Tech. In response to the last item on the list, do you think that you might take a plunge into the dialogue over whether there is greater or less workforce requirement employment impacts of different types of technology evolutions? I see you focused on mostly the workforce skills and requirements, but do you think that there'll actually be some sort of sophisticated systems analytic approach to input-output and where are the jobs going to come from and how many jobs

might they be and how might that total change in the evolutionary process?

MS. BATTERSHELL: I'm not sure how much modeling of the input and output part there will be, but I know that one of the topics that they're trying to come to grips with, and we tried for the last QER, but didn't have enough time to get there, is just trying to capture what the actual workforce is. We would look at things like rail, energy workers in rail. It was like, you know, 50. And I'm like I'm pretty sure that's not it if you look just proportional how much energy is transmitted by rail.

But one of the things that we learned so far is the data of energy workers is not great and we are trying to make some inroads into just getting a better idea on the data.

MS. BROWN: One of the hypotheses might be that as we transition from a grid that's heavily dependent upon natural resources to one that has less energy consuming, that one might expect you'd be replacing some of the prior

expenditures on resources into expenditures on employment.

MS. BATTERSHELL: There's certainly --

MS. BROWN: But that's a very radical and contentious proposition.

MS. BATTERSHELL: There's certainly a huge shift in where they are in different industries, but we've got some quantification issues, as well.

Okay, sorry. I went overtime a bit, but I don't think a lot more than I started late.

MR. MORRIS: My question's about the North American integration part and the dynamics between the Northeast and the Northwest on the 49th parallel. They're probably the most interconnected with the Northwest being highly interconnected. And maybe Eastern Canada wanted to be more interconnected with the Northeast part of the United States and then in between.

I guess my question goes into the real constraint, you know, there's a natural arbitrage market on the West Coast down to California,

because that's where the constraint is, is from the Northwest power pool down into the California ISO. And I guess part of the question is, do you think you're going to be approaching that regionally or kind of holistically across the border?

And then it's almost impossible to separate out the natural gas question because, you know, MTB used to back up renewables in the U.S. is kind of part and parcel of that entire discussion. So I think that's my question.

MS. BATTERSHELL: It is impossible to separate out the gas questions, so we are looking at, for the North American integration issue, both the physical electricity system and the physical gas system. But we're also looking beyond just the physical and we're looking at is there some regulatory harmonization? Maybe not the regulations themselves, but at least their guiding principles.

We've had a couple workshops on the border issues, one with Canada already and one

with Mexico already, and looking at the differences of how integrated Canada and the U.S. are, but not hardly at all on the Southern border. And so we're looking at a range of issues like that. But we do recognize that it's hard to separate out the gas issues.

CHAIRMAN COWART: Anything further? All right, thank you very much.

Next, I think, Bill, you're up.

MR. PARKS: Good afternoon. Great to be here again. We're faced with we have some new members and we also have some older members, so I apologize to the older ones that have seen all this or at least the majority of this. But I really felt it was important to kind of frame everything so that we had a common understanding of kind of where we're going and all, so please bear with me.

I'm Bill Parks. I work for Pat, but I also chair the great consortium that you're going to hear about in a minute. Kevin Lynn is my co-chair. He's out sick today, so he apologizes

for not being here.

We do have a laboratory consortium. The lab leads are Carl Imhoff form PNNL and Bryan Hannegan from NREL. Bryan's not here today, but Carl is here for me. And please direct questions to him, as well, in fact, especially the hard ones.

So I want to walk through quickly what is the grid modernization initiative overall. And then we really had some action that made some awards through the labs that we want to just frame for you so you have an idea of what they are. I'm trying to give you a snapshot of things. We'll leave the presentation. Obviously you have and we can have a follow-up conversation.

So why grid modernization? I don't think very many people in this room need an explanation of this, but we are seeing changes and those changes are happening at a much faster rate than they've happened in previous past decades, or at least three or four that I've been involved in this field. And they're complex changes that are

happening at the same time and I think you've pick up in elements in what Carol said and what others have said in their questions of how this is being reflected in things like a more decentralized look at the world and those types of issues, security issues.

The initiative is something the Secretary two years ago asked us to put together. He said, listen, there's a lot of confusion in this space. What we want to do from the Department's standpoint is put under one umbrella the grid modernization issue. The cross-cutting activities are happening in the Department, especially within the Office of Electricity and the EERE, and make sure those are coordinated. And, oh, by the way, coordinate the labs, too, so that we aren't having an issue where in one state we have three different labs supporting three different offices within the state and not in a coordinating manner. So can we help solve some of that and yet continue to bring value to things?

And we continue to say the grid remains

a critical platform for prosperity. We see that as the next century unwinds and so we think, and I think a lot of you would agree, that it's a critically important piece of the United States' infrastructure.

And if you look on the right-hand side we've been concentrating on six attributes, and I'm going to come back to this a couple times, because we really want to try to, as hard as it is, take a shot at what are the future metrics that we need to classify where we're going. And of the 42 or so reliability metrics today, which of those really apply to a grid 20 years downstream that looks a whole lot different than the grid today? And the same for security, affordability, flexibility, sustainability, and resilience. Yes?

MS. SANDERS: Sorry to interrupt, but I'm wondering where safety is in this?

MR. PARKS: So, right, thank you for that. Safety, we have captured in our words in the write-ups, it's hard to put everything in, but

safety is a consideration. It's been traditionally treated somewhat like reliability in that it is something we do, but we didn't tout it in trying not to have too many at a time. But safety continues to be an important thing.

And I think the way we would say that is affordability, safety, and reliability were crucial to the industry as it formed up. Those don't drop away. We also are adding these new features that we want, like the security, different kinds of security features on top of things, but we cannot ignore the old ones in addition. So that's how we would say that. We'll come back to it in a little bit.

So you heard a little bit about the drivers of change, the Quadrennial Technology Review was the second on that was done this year. QER 1.0 finished last year. These are the drivers, I think. Again, we have more explanation in our multiyear program plan that is out and up on the website. But as you look at these, they generally fit in the direction that QTR, our

activities, and QER are all kind of moving in the same thing.

The multiyear program plan that we produced is a major deliverable of QER 1.0. So if you look at the electricity section, the first recommendation is to define a plan for doing research in the areas that we're going to talk about, these six areas that we've combined. And I'll go a little bit more into this.

What we're saying is if you look at the drivers of change to that and what we've defined as really the goals for the next three or five years coming out of the Secretary's definition of what he's presented, looking at QER and looking at all the plans out of Pat's office, out of the EERE and APRA-e and others, the multiyear plan tries to capture where's the Department going in these six areas, and then making sure that those combine. And the way we talk about combining them is really start as early as late FY '17 regional demonstrations. And I'll talk a little bit about what these are, the idea that this will help

characterize and drive us toward a modern grid. We're not going to have a single modern grid in the example. The idea is to do a set of demonstrations regionally that tell us this is what the region needs, this is what we want to try to understand, that relate back to these topics, to relate back to those drivers, and the attributes at the end of day that we really want to accomplish with this system.

(inaudible) of the Grid Modernization Initiative, we formed this lab consortium. We have 14 of our national labs working in the grid space in one or more of those six categories that were up there. We made a lab call last year. We awarded those, the Secretary announced those in January. We have 88 projects that have been awarded.

I'm going to talk a little bit about what the projects look like and give a couple of

examples, just to give you a flavor for the things. All of these are up on the website. You can look at each one, but we just wanted to capture this.

But the two parts to this were we actually, in these 29 first ones, we've really reached across and asked the labs to work together. Many of those have four, five, six labs working on a topic together. And we've asked the programs within DOE, especially across EE and OE, to work together on funding these activities. So these are co- funded from the DOE side programs and their co-executed, or multiple lab executed, at the same time.

In addition, under that lab call, we put the grid related calls by the offices, the different programs. So if you look at solar or buildings or smart grid or storage, they were embedded in this for the lab work. And these are up to one-, two-, or three-year awards, depending on it. There was about $220 million.

A really important point is, although

this was a lab call, there was tremendous partnership involved in this. And if we look at this: 24 utilities, power providers, 10 RTO STOs, 15 universities, 6 state agencies, 5 regulatory and policy associations, standards, and industry players, so we have a really, really nice snapshot of the players.

EPRI's a player. NRECA's a player and (inaudible) is a player. CALICE is a player. The state of New York -- NYSERDA is a player. One really interesting one -- I've been in this game a long time -- is that -- we have a California one I want to talk about in a second -- NYSERDA was one of the members of the California project, a little unprecedented. So people in states are working together in ways in this space and looking for solutions in this space, beyond what is normal and has been. And so we see it as a really exciting piece to build on.

And in addition to the lab call, we'll continue to go out with the university and industry calls throughout the bigger grid

modernization umbrella, but we are concentrating on getting our act together on our programs and trying to get as much leverage as possible, internally and with our partners.

Core activities. So I mentioned that there's six projects here that we're really concentrating on for a couple of years. Metrics and baseline. Trying to establish -- okay, if I have a world that I want those attributes, what are those? And the idea is that we can define these the best we can and, as discussed here last time, this is a nontrivial exercise. This is maybe the hardest project of all of the other things that we're to do.

Can we establish a baseline that we measure our demonstrations against in the future? And, again, for future metrics that we're really interested in. And then we also have concerted efforts on grid architecture, interoperability, device characterization, evaluation, and sensing and measurement strategy, and that kind of thing.

What do we really need as we think about

a distribution system to give us the visibility into that system that we need without all of the excess data, or anything else that it could be. And how can we do that in a cost effective way and looking at what are the solution sets that might be found there?

As part of this, we also made 11 awards to the labs to work with states -- and this is a collection that you can't read very well -- as well as showing how the labs are regionally placed and we put leadership into those labs that were close to the projects. So I'll just give a couple of examples. There's a Southeast project that is Savannah River and Oak Ridge are looking at. A combination of things in the Carolinas, Georgia, and the Southern territory, and in Tennessee looking at how to think about DER in the future and the distribution circuits might happen in that arena.

We are consolidating and reinforcing some of our New York REV work that we're doing. Brookhaven is taking the lead. Brookhaven's in

New York on Long Island, as an example, so to coordinate that effort and response to the New York requests we're getting. We have a Midwest SEEMS project that covers really looking at the Eastern and Western interconnection with MISO and SPP about how do we think about moving bulk power around? How does that affect bulk renewable power? And there's a corollary project in the wind side, looking at the Canada-U.S. inter-ties. And so together we're linking a lot of projects that we haven't before.

Even though you've seen wind do that kind of work before, you've seen us on the OE side do that kind of work, and other projects. We're trying to coordinate all of these in a way that we haven't, so we're leveraging ourselves better than we have in the past, as well. That's a very significant point, instead of spending a million dollars on something, maybe we're spending 6- or $7 million on a topic and increasing our impact on that, as well leveraging our partners better. And, of course, getting the buy-in of the partners

and the ownership because ultimately, again, we as DOE do not implement this at the end of the day. It's implemented at the state or the utility level.

In Alaska, there are a couple of themes that show up. Microgrids show up, resiliency shows up, high penetration renewables show up. So coordinate those projects and those activities, and back to the other foundational projects that we're working on.

This is an eye chart. I'm sorry, but I just wanted to give this snapshot, that these are the projects under the six areas that are co-funded across the offices and the programs. And they range -- we wanted to make sure we had activities in each of those six buckets. And, again, there's some connections across, as well, but this was our starting point, in addition to the first two things I started about.

And I'll just read a couple of topics just to give an idea. We're looking at how you tie BMS, DMS -- Building Management Systems,

Distribution Management Systems -- and overall management systems together today, but we're also talking about what's the advanced control theory that you need for the next generation?

So how can we help some things in the shorter term, as well as what do we think fundamentally could change about controls, as we think about all these operating together at the same time? So it's a package that we're looking at.

We're looking at ways to tie cybersecurity into everything else that's going on and to build it in inherently from the ground up and not just be an overlay. As we look at things, we're looking at how do we take distribution and planning tools and tie them to operation and decision-making at the same time, so that we end up with a coordinated suite of tools and models that we can use to inform different people in different fidelity levels and yet have its basis in reality? So those are the kinds of things that we're trying to accomplish.

Again, I'll just drive on one for a moment. On design and planning tools, one of our six areas, how do we get open software platforms, 50X speed-up for advanced computation? We've already seen some applications of this at the ISO level and in some of the modeling work that we've been doing on the OE side for a couple of years and building on advanced computational techniques and parallel processing, all taking problems that sometimes took 30 days to 3-hour solution sets, those kinds of things, so that people can act in more real time about what they're doing.

How do we add capacity to model uncertainty? How do we get more understanding of the variability of what we're doing? And some of the key projects in this one, DER Sighting, an optimization tool developed for California with the idea of how does everybody use it. A North American renewable integration study, Alaskan microgrid partnerships, multiscale production cost models development. How do we tie those all in? Computational science for grid management and

extreme event modeling, all those things we're tying together under this package and saying, as we execute, think about how all those things come together. And we've done that for each of the six areas.

An example of the California one is, we think about the drivers of change, we think about the specific challenge that we're trying to do, and the specific partners that we have, and the areas of the multiyear program plan on the ranking side that we're touching in order to do this. So we're getting our own cross-fertilization and keeping an eye on the drivers of change and the attributes that fundamentally want while helping people solve a problem that they're tackling.

This is a different one for New Orleans, looking at the resiliency issue that we have. It's really interesting -- I don't know if people have seen it -- but since we awarded this, Rockefeller's stepped up and put even more money into this. So we're working with a suite of partners and New Orleans is looking at the

anniversaries of hurricanes, anniversaries of the city, and they're really trying to step back and take a very serious look at what they really want from their total energy picture and how does electricity play in this. How do microgrids play? How does resiliency play? And that kind of thing. And so we're helping them with that, as well.

And then, again, back to the longer term research development, we have a suite of these things. In this case, the multi-scale integration of control systems. You can see Argonne, Brookhaven, Los Alamos, Lawrence Livermore, NREL, PNNL, and Sandia are all working together on this project, the idea of an integrated grid management framework that's similar to an autopilot system for greater interconnection activities.

So, can we create an open system? Partners are PGM Duke, PG&E, Alstrom, and EPRI. And you can see how this goes, so about a $4.5 million equity over 3 years. It's just an idea of the kinds of things that we're trying to do. And, again, we have 88 projects that were awarded.

I talked about the three demonstrations. Real quickly, this is how we're trying to pull it together at the end and we'll continue to talk about are these the right ones? We talked about this a little bit last time. The idea is can you reduce reserve margins and hold a system reliable at the same time by utilizing DER, Demand Response, or all the other new things that are emerging, storage at the same time, and not put the system at more risk while you do that? Is that an achievable thing or not, to get a savings as things shift?

A new capacity for grid operators to leverage and manage the distribution resources, and how do we get data- driven tools into the thing? Target partners will be transmission utilities and system operators. We see these set of demos as we would go out with FOWAs that would be regionally focused? And can we put the right kind of partners together, part combinations of utilities and co-ops and states and universities? Because it's going to take a complex set of

partners to address these complex set of issues for how we're looking at this.

The second set of them that we've seen are, okay, our investments were significant, but from a technology standpoint they ended in 2012. So as we move along, as we take advantage of the work that we've done and the private sector's done, that RBE's done, that others have done, EPRI's done, can we bring all that in and say, okay, let's start talking about showing advanced systems, what they can do in a way to go beyond the AMI deployment, to go beyond and take advantage of what other tools we need to get to the sensing and the measurement and the control that we might have?

How do we think about coordinated microgrids? Less outages, few times -- again, multiple attributes at the same time and targeted at distribution utilities and cities and MUNIs.

And lastly, can we use these coupled planning models that are much faster, that are really focused specifically at the problem of how

to control electricity better, and work with them to make sure that that gets to decision makers or the results of that get given to decision makers, so they really have an idea of how to evaluate things like new business models and impacts on policy decisions? And our targets for those are states and local regulators, utilities, and market participants.

So, as we look, we made the awards. This week we've actually finalized the statement of work for 24 of the 29 foundational projects. The other ones are also moving forward, so people have actually started to work on the lab projects as of Monday. We are continuing to finalize all that.

We are also doing regional workshops. We're doing them in coordination with the QER 1.2. We're actually going to co-locate them in Boston in April, the two meetings. We're hitting some of the same places, we're overlapping on themes, trying to support each other as we go out. But we're doing a slight different focus on this and

our focus is we want to talk about is our multiyear program plan on target? Is it going to help that technology policy regulatory interface as we move forward? And what things do we think are gaps in what we're doing? And as we think at the end of this, we'll probably go out with the next version of the multiyear plan, getting much more detailed cooperation from stakeholders, and the whole thing. And, again, regionally based.

So we held our first one in Austin two weeks ago. John was there. We spent a day and a half talking about different issues and how they all come together, and then how that will affect our projects as we go forward.

And at some point this year -- we've shown it as June -- we'll have a D.C. summit where we really talk about how this is the snapshot of where things are in conjunction with the whole effort that's going forward.

So, again, really what we want to do is ultimately have national impact by doing it through the process that we've laid out and doing

it through regional demonstrations and understanding regional partnerships. Thank you very much. Carl, is there anything you would add to that?

MR. IMHOFF: Nope, that's really it.

CHAIRMAN COWART: Thanks, Bill. Any questions? We've got a couple of cards up. I'll start with Carl.

MR. ZICHELLA: Hey, Bill, great presentation. I'm going to have to go back and get your slides to walk myself through it again. That was really amazingly detailed.

MR. PARKS: Thank you.

MR. ZICHELLA: A question that I have is about North American integration and not much focus on Mexico. Here we have one of our largest trading partners completely reorganizing their electrical sector, looking a lot more like the construct that we've had here in many of our RTO situations with an independent system operator, et cetera.

Huge opportunity for climate change

where the economy is almost completely run on hydrocarbons. It just seems to me like we ought to be focusing there, too. I get why we're doing Canada, and obviously we're much more interconnected there, but the opportunities for us to have a more rational set of interconnections with Mexico exists.

There's interests in bolstering interconnections in Arizona, Texas, California -- we're already pretty well interconnected. Can you just comment on what the think is about Mexico?

MR. PARKS: Yeah, I will comment for a second and then I'm going to ask Pat to comment, so I'm going to give her a minute to get her head together. That was a warning, Pat. (Laughter) So, as OE we've been working as part of a trilateral for years that included Mexico. That's a very important thing that it continues to do and part of OE's function is to approve cross-border permits. Those come from not just Canada, but from Mexico, as well. So that is an activity that -- and we're aware of some of the planning because

of those meetings that have gone on.

There is a lot more action right now in Canada because in part some of the states are reaching directly to Canada and asking for permit activities, and those kind of things. So there's just been a larger recent -- the last couple of years -- activity that's been more bilaterally focused, especially in trying to think about moving the hydro and the wind interconnection down from the provinces in Canada.

I think in the end of the day, as you heard Pat say, the Secretary's interested and I think there will be continued interest in how does the international world play, and part of that is the North American grid because, at the end of the day, we do have a North American grid. I think it's a great question. I don't have specific answers on the best things to do in the short term about Mexico, but there's certainly an awareness of the situation in the kind of things that they're asking for help with.

MR. ZICHELLA: Just a quick follow-up.

Is USAID on your list of partners? Because I've run in to them several times in Mexico on the electricity reorganization issue. They've had staff on the ground working on it, and State Department, obviously, too.

MR. PARKS: That may be one way to look into where that's headed. We don't have the same interconnections we do with Canada, but we could.

MR. IMHOFF: So my personal experience is that USAID is, as we've continued to rely on communications back and forth, we in the Department just had someone come back from being on detail to both USAID and the World Bank, so we continue to have those kind of interplays and connections.

In terms of really formalized, I'm not cognizant of that. Things have been more topically described type things and we've had some discussions about portfolios. At the end of the day we've tended to play historically more on the technical side of international standards, those kind of things, helping with ISGAN and those type

of activities. Different standards, but that's my simple answer to that.

I think that's something that, depending on how things go, will emerge in different ways. Pat is there anything you would want to add to that? Or Liz?

MS. DALTON: Yeah, so I apologize. I stepped out and just came in on the tail end of your question, but it was actually to get on a call internally to get ready to talk about this exact topic. (Laughter) Technical difficulties with the phone connections, so I wasn't able to connect.

But the Secretary, as Pat mentioned before, heavy focus for the North American trilateral arrangements, including Mexico, obviously. The Secretary was in Winnipeg several weeks ago for the North American trilateral conversations where several of these issues came up. We talked about things like the -- and I'm sorry if you all did this while I'm gone, but the regulatory side-by-side that we have with Canada,

trying to do the same thing with our Mexican counterparts.

There are some other things like road-mapping that we were talking through this afternoon, so stay tuned. I'm sorry, but if I'd had 15 more minutes of connectivity we could have better answered that question for you. We can follow up, certainly.

MR. PARKS: Next meeting. Any other questions?

CHAIRMAN COWART: I'll take Wanda, Paul, Anjan, and Pam, in that order.

MS. REDER: Bill, really good presentation. I applaud the organization of it and bringing all the lab activity together. I know that's a tremendous amount of work. I especially liked the two things on metrics and demonstrations. Beyond that I am left with the question of adaptation seems to be the challenge and I know you're working very hard to reach out to partners to try and get them involved in the process. The workshops are certainly part of

this, as well, but can you expand on the thinking that went into the release of the 88 projects, kind of from a macro scale? How you're going to get this activity and get it into the mainstream of operations?

MR. PARKS: So, I'm going to start that and I'm going to let Carl finish it, so I'm giving him a head's up this time. Our thinking was, really, we needed to, in part, make sure that our internal efforts were well oiled and working together. And that was part of why we focused on the lab call first.

We also are looking -- there's some broader themes that fit into that, that not only from trying to have an impact as related to the QER, but also to have impact on how -- the Secretary has a great interest in how to make the labs more impactful overall, and this is one of the topics, but there are more topics that fall into that. So it was also how do we be smarter about engaging our labs in our mission space? That factored into some of that. That says work

on the lab site first. And as soon as we turned to the lab site, again, the partners became critically important in that and that's why we went the way we did.

We are looking at how are we going to have FOWAs that relate into both what we're doing now and the gaps that we've left from what we see are out there. And how do we get things to implement more? There are discussions going on, on the RBE side, on how do we be more successful at getting the commercialization side into play there? The Secretary and the head of RBE are having those kind of discussions now. So we're looking at how do we get more effective as an organization at getting real things into the market faster?

The types of things that I think are crucially important and I still feel at times we're like the Russian Front, you know? It's 2,000 miles long, type of thing. And so it's what we continue to look at and it gets a little bit back to what Pat was saying at the beginning.

What are the strategic priority things that you do now and what are the things that flow a little further down the road? We've tried to roadmap and look at those kind of things.

So I think, unfortunately, we're still going to be in some places a little more piecemeal than we really want to be, just because of the reality of funds and the situation with people in and all. And that's why we're also trying to tie both the short term what are the state needs into the longer term. What do we need to really have an integrated system across -- and answer some of the questions about how integrated is that system at the end of the day?

So all those things are in play. I don't have a simple answer to all of that, other than we think it's really important to stir it all and look at it and say what really floats in terms of priorities? And what does that tell you about timelines of things? And some things simply aren't ready. People have concepts that they throw out, but there's really not enough

information about does that make sense? And we're doing that ourselves in the transactive area. We think that could be an important thing, but exactly how that plays in what regions -- so we want to test drive that at Washington State and some other places and expand what we did on the RS side because we learned a lot of useful information, but not enough to say, hey, this is what you want to set up, and we would suggest that you do, if you are a state or a region.

Carl, would you like to pick up on that?

MR. IMHOFF: Does this work? Great. So to add to what Bill said, Wanda, at the core we're working on generating new knowledge, open platforms for next generation tools, and next generation data sets that should accelerate the engagement with the ecosystem of vendors and utilities in the states. So by design, we will have advisory groups that will include all of those stakeholders working with us in the development of this next generation of new knowledge, platforms, data sets.

You also saw that immediately we'll have 11 regional demonstrations where we'll get regional engagement right away from day 1 as a starter set of engagements. And then in the regional workshops we're holding we're asking each of the regions to begin to illuminate the emerging regional priorities for grid modernization, with the intent that in two to three years, as some of these products come to fruition, we will look to if funding's available, that next round of regional demonstrations that would help demonstrate this next activity, working with those stakeholders, the vendors, the utilities, and the states.

So it's orchestrated engagement from day 1. Open design with engagement of all the stakeholders and the development of the new products aiming towards this next round of regional demonstrations. And we had a conversation with Anjan's subcommittee today about the high value that we would see of the EAC subcommittee helping frame those critical

legislative and regulatory questions that they would like to have answered with this next round of demonstrations, so that we can make sure that we're aiming at those very directly.

CHAIRMAN COWART: He's got the -- David, did you have a quick comment? I know there's a line.

MR. MEYER: Yes. If you recall, there was an announcement in mid-February about the formation of a clean energy coalition by 17 governors and these included the governors of Hawaii, California, New York, Massachusetts, Ohio. And I don't remember all of them at the moment, but at any rate, this immediately registered as an opportunity for us because we're already working with some of these states and the others are saying, hey, we see the need to do this. And so we have reached out to the people who helped to organize this coalition and said we've got something we think you would be interested in. And they said, you betcha.

And so I think that's another avenue.

And by pursuing these kinds of opportunities we will make some very significant headway, I think.

MR. PARKS: Thank you. Rich?

CHAIRMAN COWART: Next up is Paul.

MR. PARKS: Oh.

MR. CENTOLELLA: So, Bill, I want to just ask about something that I think maybe I had not fully understood before I saw it on your presentation, and that is the demonstration about the lean power system. I had previously thought about this not so much as focused on lean reserve margins, but on better asset utilization, whether that's at the demand level, transmission topology, voltage management, et cetera, taking some of the variability out of the system, so that the system is overall more efficient and more affordable rather than just trying to reduce reserve margins.

And I'm wondering where that broader question of system efficiency fits with respect to the things that you're envisioning going forward.

MR. PARKS: You're exactly right, Paul, I just went too fast in some ways in trying to

summarize things. But all those things -- because what we really want to do is look at what are the suite of options that we have and what makes sense for that regional transmission-distribution interface area to look at what are the kinds of things that we could do. So if demand response, as an example, can play harder in one place and play up to the transmission wholesale market -- assuming that you get all the rules right for us -- that that's an option that would factor into that.

The reason we want to think about trying to do more than one of these in places is we're going to have different solution sets in different parts of the country.

So, Carl, any more you'd add on that one?

MR. IMHOFF: No, I think that covers it, Paul. Those other items are in there in terms of dynamic (inaudible) rating and other things to get more utilization out of the assets, help better exchange of power across the regions, et cetera.

But also then run closer to the edge of the system you have as long as we can validate that we can maintain reliability.

MR. CENTOLELLA: So that you have some success metrics other than just reducing reserve margin then in this project.

MR. IMHOFF: Yes.

MR. PARKS: Correct.

MR. IMHOFF: Gordon?

MR. VAN WELIE: Hey, Bill, how are you?

MR. PARKS: Okay, great. How are you, sir?

MR. VAN WELIE: Well, thank you. So I thought that was an excellent presentation and I have a few assumptions about the presentation which you might want to clarify for me. And then I have a question, I guess.

So, listening to this, I find it both exciting and frustrating at the same time. And what I think when I say that is this discussion around the lean grid or, I think, the previous speaker mentioned the hybrid grid, and something

we're spending a lot of time thinking about and worrying about because we're in the middle of it right now. And if I look at this as an engineer and I say I think it's a really good idea that somebody's looking at the technical feasibility of what's possible. So that's the exciting part.

MR. IMHOFF: Right.

MR. VAN WELIE: The frustrating part about this is that I don't see anyone looking at how we get operational accountability and financial accountability in order to make what might be technically feasible possible. So we have a split regulatory system in this country and so the financial incentives and the operational accountabilities of resources at the distribution level are completely different from what is happening at the grid level, at the wholesale market level. And yet if our assumption is that we're going to have a hybrid grid, to use the term in the last presentation, which is a term that we're using more frequently now.

If we can have a hybrid grid and we

expect all of these resources to show up when we're in a 30-minute reserve deficiency, what we need is a system operator, is operational accountability that's consistent. When you say the words "operational accountability" it means that you need to present the same set of financial accountabilities or financial systems.

MR. IMHOFF: Right.

MR. VAN WELIE: So what worries me is that we are way ahead with regard to our engineering thinking about this and we're way behind with regard to thinking through how to structure this in a way that is even feasible.

MR. IMHOFF: So, Gordon, I've lost sleep over that and I'm sure you have, too. And in our Austin meeting and other meetings people have also reflected that, wow, there's some disconnect. And we went around and asked questions at different meetings of what's most important to do first, kind of thing, out of prioritization. And it's like, well, if you can get more clarity on that regulatory policy front, that would sure help us

make decisions because we can move capital, and then things to do that.

At the end of the day, it gets back to -- I think, as I look at this, you look at some states have 2040, 2045 goals, that kind of thing. We're not going to do all of this in the first wave of demonstrations. We're just not going to, it's too complicated. There are too many unresolved issues for my viewpoint.

So the question is, can we still think about leapfrogging a set of demonstrations over time, every five or seven years, where we tackle as many of these things as we can or we get them embedded in the thinking? And even if we frame things, even if we don't know all of the answers -- one set will do of the demonstrations -- at the end of the day we're not going to prove it all out by five years from today. It's too complicated.

So can we take reasonable but aggressive steps that lead us in the direction while, at the same time, recognizing some of the questions that people are trying to answer in real time today?

And how we connect those, if we can short-circuit some of that? And that gets a little bit into why we want to try to tie some of these future models and planning activities together because if we can create the story of how the regulatory and policy world should move, or the options for it to move, in order to get this into the marketplace, not just as a demonstration, but I think we've advanced the discussion further.

But at the end of the day it's a very hard proposition and I think it's going to take iterations to really get us at major changes of that.

MR. VAN WELIE: I guess my question is who has the responsibility for looking at this problem?

MR. IMHOFF: Well, I think the answer is that it's not a single entity. It's not going to be -- from my viewpoint, and others can speak up. And so that's why it's really, really important to form regional teams. The team has enough of its members that say, okay, collectively we could move

that space.

And there's some few examples of where we've done that. We did that in Hawaii, where we had the consumer advocate, the governor's office, the state legislature, the prime utilities, and all the decision makers that had to move major decisions, make compromises, and go forward with those compromises, to try things out and to say, okay, you can take a risk on this. It's not too big a risk right yet, so we'll take that risk and move it forward.

And that opened up lots of actions at the PUC level and that kind of thing. The key to that, that we see and how we're trying to apply this, is to remain vigilant. So that if you make a really dumb mistake or what turns out to be an unintended consequence, you also have the players at the table that can make corrective actions in those kind of things.

It's not simple, as I see it. It's not simple at all. And I think you're going to see people take off bites like New York did, and

saying we're not really going to tackle all the regulatory state jurisdictional issues in one bite. We're going to think about what things we can do now that the state controls as part of the rev activities.

MR. VAN WELIE: Could you at least through this process tee up the unresolved issues?

MR. IMHOFF: I'm sorry, Gordon, I missed it?

MR. VAN WELIE: That at least through the process tee up the unresolved issues because there's an educational component to this. I think a lot of folk focus on what's technically feasible without thinking about the other dimensions of the problem. And it's not that they are deliberate -- the exciting stuff is around the technology very often --

MR. IMHOFF: Right.

MR. VAN WELIE: -- and the really hard stuff is around the policy and the jurisdictional stuff. And so at least exposing that there's this list of unresolved issues that has to be worked

through, I think, provides some balance in the communication.

MR. IMHOFF: I think that's a major outcome. I'm sorry, just let me answer quickly --

CHAIRMAN COWART: Wait, we're way over time here and I know this is an important dialogue, but I would like to hear Pam's question and then we'll need to call this to a close.

MR. IMHOFF: I'll keep it really short. I agree with you and we need to think about it. And I think that education replication abilities are applied to what's useful is a critical piece of all of this. I think we've failed. If we demonstrate things, we don't have an ability to really let people utilize and build on that in a constructive and relatively fast way. Then I think we've really not been as successful as we want to be, despite all our neat technical things that we're going to do.

So what it says is that we've got to be smart up front, we've got to really craft these, and it gets a little bit back to the metrics

discussion. What do we want to prove out as we do this demonstration? Which of these attributes? Which of the policy things do we want embedded in this to answer what questions for each of those demonstrations. And we need a set of solutions for each of those if we're going to truly advance the ball, from my viewpoint.

Thank you very much. I really appreciate it.

MS. SILBERSTEIN: One more question, and hopefully somewhat easier, there is a focus in the MYPP about valuation. And we just heard from the previous speaker, a big focus there, too. And just from a policy and process prospective, are these dual, parallel, interlocking efforts, how does one fit into the other? It's a topic of big interest to co-ops and just how best to engage here?

MR. PARKS: So, if you recall -- and I think you were at the meeting we had a little less than two years ago on a thing -- a couple days. Actually it went fairly well and we built on that

jointly and we're building on the activities jointly now. We're trying to, from our side and the live side, really reinforce what EPSA's doing right now with valuation. David, I believe, is on a planning Committee that's looking at a valuation workshop coming up in the next quarter or so. So we really have restarted that effort a little more aggressively, but in tandem with EPSA on how we're going forward.

So hopefully, we will speak pretty consistently about it and we will also be very transparent at what we're looking at. Thank you again.

CHAIRMAN COWART: Bill, thanks very much.

MS. HOFFMAN: So while we're transitioning, I just want to correct the record. I know David talked about -- it's the Governor's Accord for a New Energy Future, so if you do a Google search, it's the Governor's Accord for a New Energy Future.

CHAIRMAN COWART: Thank you. Anjan,

you're up.

MR. BOSE: Okay, so I think it would be good to have the last slide that Bill had on as a backdrop for what I'm going to say. And, actually, what I'm going to say is, I'll just put it more briefly, I think, than what the discussion was.

Actually, Gordon brought up most of the things that we talked about this morning. But there is a working group on this grid modernization that I chair and we have had a few phone calls and two face-to-face meetings, the last one this morning. And the question is how we can help -- you know, I put that up as a backdrop because you've already heard about the multiyear plan and you've now heard about the first move on that, or the projects being done by the labs, and so the question is, what are in all these plans and these projects that the EAC can comment on, can help with, and can maybe provide some guidance as we see this thing move out?

So we had a far-ranging discussion this

morning, but here a three things that I wrote down that maybe would help. For the first question is, what is the appropriate federal role, specifically the U.S. Department of Energy role, in this field, in this area? Because as many people have already pointed out, the acceptance of all of this depends on state and the industry as a whole and these are all kinds of multiple players involved, and this has been pointed out.

And I think there is a relationship between what you heard from EPSA in their QER second phase, looking at the policy side of things and the research agenda that Bill talked about, one. And the second one is exactly what Gordon was talking about, the connection between technology and policy. And this is particularly acute in this area of grid modernization because a lot of the research agenda is looking at system-wide things like operations or planning, and that's directly affected by policy issues. And so then the question is, how do we suggest that the people doing the research make sure that

we just don't do feasibility research and say, of course, we can do this engineering-wise or it will never get done because there are all kind of things on the way. So the question is how do we suggest that the researchers talk about the difference, the things that the technology can do and how the different kinds of policies would affect that technology?

And let me just give an example. You know, it's one thing to talk about something like a PV panel or storage technology. And you can talk about how good it is, how much it costs, and how its performance is. But when you say that, well, what is the penetration level that you can handle given the new technologies? That's the question that comes up when you're looking at the systems type, this kind of issues.

And so we need to give some guidance to the researchers on this as to how to put out their results. And then that leads us to the third point that I had here that was on success metrics. And, of course, there is one of the main projects

for the labs to do is the one on metrics, so that's not what I'm talking about here.

What we talked about on success metrics is how do we make sure that all of this technology that's being developed has a pathway to actual adaptation by industry? And it seems to me that -- and we've talked about demonstration here and there obviously has to be some demonstrations to do the convincing of the technology, for people to adopt, but it's not that simple what the research can do. How is the research going to set up for these demonstrations, and what are the right demonstrations, and would the demonstrations actually give the right kind of results? What will it take to do the convincing?

And we kind of focus in on two areas here. One was the simulation because most of these systems-type large things, nobody's going to put into practice until you've actually simulated it and showed some promise before you even try a pilot type of a project. So simulation is one important thing.

And the data. Simulated date is not enough to convince people because people will immediately say, well, your models are no good, or whatever. So you have to make sure that the simulations that you're doing is actually based on real data, from the real world, from the people who are actually operating the system.

So that's, I think, a very critical part of these things. And these are three areas with many sub-areas that we thought that the EAC could actually help in setting up some guidelines along these lines.

So I'll leave it. Maybe some of the EAC members who are in our morning meeting, or others, would have a comment?

CHAIRMAN COWART: If someone has just a quick comment about the morning meeting, we can take it? Otherwise we're going to move to a break. Yes, Phyllis?

MS. CURRIE: Well, one of the comments that we did talk about a lot was that even if you have technology that is demonstrated to be

effective long term, or has the potential, one of the challenges is that the investment required to deploy it requires a lot of actions at state and local levels. And how do you get the general knowledge out there so that deployment has a more receptive audience?

So we talked about one of the roles that DOE can play and we were told that it's really not in your mission to educate. But education is really essential because so many laypeople don't understand this industry. Our industry is full of acronyms, so you have to speak in plain English to people about, really, what's the status of the transmission and distribution systems today and what's in the future. And how do the technology investments that we find are going to be valuable, why is there value to approving the rate increases that will be necessary to deploy?

So, again, that was a lot of discussion around how do you bring that overall knowledge to the general public so that they will be supportive of these investments?

CHAIRMAN COWART: All right. Thank you very much and thank you, Anjan. We are behind schedule. It's not irredeemable, but we're up for a break and I would like to take a break. And it won't be a sloppy 15 minutes, it will be a sharp 10. And we're going to come back and get going right away. Thanks very much.

(Recess)

CHAIRMAN COWART: Unlike the really thorny questions that we just dealt with, we now have a panel on the easy stuff. The valuation and integration of distributed resources and Paul Centolella will take this panel. Thank you, Paul.

MR. CENTOLELLA: Thank you, Rich. So it's my pleasure to have here what is really a stellar panel of experts. I think we're, if we can get that up, you'll see a summary of their qualifications. I won't try to go through all of it or I could spend most of the next hour talking about what all these guys have accomplished.

But, you know, what we try to do, what we've been trying to do in the Smart Grid

Subcommittee is to go from this issue of, you know, looking at DER kind of from fixed viewpoints that many people enter this discussion at. You know, that DER either is a cost or that it has 30 different value propositions and try to really come down and think about, what does this really mean?

And so, we put together a panel of folks that is looking at this question from four very interesting, and I think leading-edge perspectives. So, our four panelists, I'll just talk about what they're going to focus on very briefly.

Bill Kallock is the Vice President of Grid Analytics, with Integral Analytics. And his firm has really been looking at the question of distribution planning and long-term forecasts of distribution value. You know, and what role DER can play in that. And so you'll get a planning perspective from Bill.

Professor Caramanis was part of the original group that put together the math for what

we now call LMP Pricing. And has now taken that work and is looking at distribution level LMPs within the distribution system for real and reactive power, as well as for various levels of reserves. And can talk about, you know, what it would mean to think about this from a more market perspective of how you could begin to attach market-based values to the products that distributed energy resources provide at different times and locations within a distribution grid.

Professor Divan is both a scholar and also an innovator, and he will talk about this from the perspective of controlling things at the grid edge. You'll probably hear a little bit about one of, I think, he's got at least four different start-ups that he's done in different kinds of control technology. He'll talk a little bit about some grid- edge voltage control, as well as talk about what are the implications of thinking about a different kind of control architecture for the power system, and how does that then affect how you think about distributed

energy resources.

And finally, we all know Heather Sanders is a member of the EAC, but she's also the person who is principally responsible at Edison for trying to implement the CPUC's distributed energy resource guidelines and manage distribution planning in a real world context where she has to actually deal with things that go wrong on the distribution grid when you don't get it right.

So I think this is going to be a fascinating panel. I won't spend any more time talking about them, I'm going to let them introduce the topics. Bill.

MR. KALLOCK: Great, thank you, Paul. And thank you for the opportunity to speak today. I apologize, I've got a bit of a cold so I'll try and flop through here. So, our company has really been focusing on trying to understand the avoided costs from way back, as far back as 2005.

And really understanding the cost effectiveness of energy efficiency, the demand-side management measures that have all gone

into DERs now. So we've been kind of focusing on avoided costs for a long time. And in the last six years we've realized that the value of DER really is based upon a much more granular avoided cost that you have to figure out what the avoided cost, or the customer's cost to serve all the way down to the edge of the grid.

Some of the customers we've been working with over the last 10, 11 years now are Duke Energy, KCP&L. We're currently working with all three IOUs in California on their resource planning. We are working with SAE on a pilot with our low-tier software that I'll be talking about today.

So, I think we all intuitively know that DER, the location matters. Putting a PV system on one part of the grid is going to have more benefits than another part of the grid. The question comes along, how much more benefits? How do you quantify what those benefits are of that PV system, of that DG, of that storage, and that's really the question that our company is trying to

answer.

So what you see here is really optimization of a bunch of DERs. This is PV storage and demand response. I'll talk about how we get to this, as we go through the presentation.

But it really starts with this matrix. And there's really four quadrants that we've kind of identified as going into the grid edge avoided costs and that is, it starts with the LMP in the lower right, and then it goes over on to the grid side, we have the fixed costs. So we're really trying to understand where on the distribution system you can get credit for deferring capacity upgrades. Whether it's a transformer upgrade; whether it's a substation upgrade; whether it's deferring the reformer, the lines.

And then going up from that into the variable costs in the grid side, where are you going to be able to improve voltage issues? Where is the DER benefits of power factor improvement, reduced line losses and other limiting factors that some of my other panelists will drill down

further on some of these.

And then it's also on the supply side. Is the DER, is the battery-frame example able to provide frequency response benefits? And how do you quantify those benefits.

So as a company, we're trying to capture all these benefits and put it into what we call a distributed marginal cost, or a marginal cost down at the edge of the grid.

So where do we start? Well first we have to understand where the grid is going to be constrained. Not where it's constrained today, but where it's going to be constrained in 5 years, 10 years, 15 years.

And to do this, we use long-term forecasts. We have three different long-term forecast approaches that we use. The first one is the spatial load forecasting. So we forecast utility load growth on an acre-by-acre basis 5, 10, 15 years out. So we can get very granular in terms of where that load growth is going to happen, where the projections of DERs are going to

happen.

And we do this through a scenario analysis. It's not just one forecast of the land use. But a probability forecast of penetrations of different DERs of different growth scenarios. And then we pull into the corporate forecast, which is the top down forecast and we do that, spread it across the customers' accounts by the megawatt hours. And then we do a circuit peak load forecast. And I'll talk a little bit more about these. But the spatial load forecast really starts with 30 years of satellite information. We pull all that into GIS. We pull a bunch of different variables in such as, different penetrations of DERs; projections of commercial growth; a hydro factory coming into a service territory; a light rail situation coming in.

We pull those all in and what we end up with is a graph like this. The yellow line you see here is the capacity of the circuit, and you can see that there's a planned upgrade in 2019. The lines you see across here, the gray line, the

blue line and the red line are those three forecasts combined. And the dotted line that you're seeing is how those forecasts are related to weather. This is key. You can't just look at the forecast and say okay, well this is what the forecast is going to be over the next 25 years or so. But you have to look at the impact of the weather on that forecast. What's that extreme weather event, and how does that extreme weather event going to impact the capacity of this -- this is actually a feeder. That's what the distribution engineer is going to look at.

So in this situation you can see that there is a weather risk associated with the growth on this circuit, but, we do our scenario analysis. We go through and we figure out what different mix of DERs can impact that. And we end up with a deferral capacity here for off-setting the intermediate upgrade. We're making sure that that system can get to that planned upgrade in 2019. So we capture that fixed cost/deferral capacity amount. And I can go into much more detail, I've

only got 15 minutes. I usually take about an hour-and-a-half on this presentation. So bear with me. I'm trying to go quick.

The next aspect here is understanding, once you understand the load on each of the circuits and each of the feeders, understanding what the technical limits are for DERs. For example, how much PV hosting capacity is there on this feeder?

Here we've got an example of looking at the loads on the feeder. Actually this is a circuit and taking a look at what the minimum loads are, we can figure out that if you constrain it by no backfeeding onto the system that this circuit can handle 7.38 megawatts of PV before you cause back feeding onto the system. It's not a percent reduction, the overall capacity of the feeder, but it's actually related to what the minimum load is. So it's essential to really understand what the loads are on a feeder by feeder basis, even down to the customer service transformer basis.

And this is the type of analysis that we're doing for utilities around the country right now. We're doing this with California. We're doing this with some of the New York utilities. Really trying to understand what the technical limits are based upon what's going down at the edge of the grid. How much load is at the edge of the grid?

Limiting factors -- so once we understand what's going on with the load at the edge of the grid, we actually combine that with the power flow models. Such as a SYME, Synergi or Milsoft. And we take those power flow models that usually stop at a node, and we snap that down to our customer level load forecast, so that we can get a very, very granular look at that power flow analysis and understand exactly what the limiting factors are. If I had a mouse, I could do an animation here. I do have a mouse. Anyway, I'll move along.

What you would see here is that we are looking at a very granular constraint of voltage

and line overloading. Oh it is running, thank you. So you can see the blue is being, the voltage being lower and the red area is showing where you're overloading a line. So once you take those power flow models and you match them with the load forecast at the edge of the grid, you can get a much more granular understanding of how the DER penetration can impact some of these load flow limiting factors. And I think some of my colleagues will talk about that in more detail.

So there's other advantages of DERs. I think we all kind of know about these. Another example here is reducing the volatility of load on a transformer. Here we're talking about the choreography of DERs. Choreographing the water heaters, the air conditioners -- in this case, this was actually a project that we did for Duke Energy back in 2008. Where this was the volatility across six residential transformers. We choreographed the loads on those transformers using our economic signal so that we could load levelize. And of course, the benefits here, are

benefits that can be quantified and put into the distributed marginal cost.

So that's a quick summary of the four matrix here. Of course, the lower right there I've kind of glossed over is the LMP. It's a forecast of the LMP over a ten-year period. But when you get this, you end up getting what we call the DMP or DMC, distributed marginal cost. Which is the blue line in this graph. And so you end up with the cost of service or the distributed marginal cost. By customer service transformer we could actually do this all the way down to the customer level. The example you're looking at is by customer service transformer. So here you're seeing that blue line, you're seeing the volatility and how much that cost of service, or of avoided costs changes by customer service transformer. Once you have that value and you have the load shapes of the different types of DER, you can actually create an optimal mix of DER by customer service transformer. And I think this is really where we're all trying to get to. It's

trying to figure out what the least cost mix is of DER.

The first step of course is to find that economic signal that DMC, and then once you do that, you can pull in the technical constraints of the different types of DERs and create the optimal mix.

Here we're actually optimizing on the TRC, the total resource cost test across the circuit. So you can see the TRC score here is .93 but the utility cost test I want to point out is higher at 4.4. So there is definitely a lot of benefits to the utility so that they could do a lot of things on the cost side as well to even those things out.

I have another animation here that takes us to another, to the operational step. Once you have the DMC for a long-term planning, we can bring that DMC, thank you for making this run. We can use that DMC and bring it down to an hourly basis to send that economic dispatching signal or prices to devices, to battery storage, to demand

response, to devices in the field. Here you see batteries in blue charging up at different stages according to the different feeders. And then you see that the red dots being the demand response or flexible demand is probably a better term or responsive demand, is you can see how that kind of feathers in to help balance the grid to deliver least cost resources.

So, some of the lessons that we've learned in California is that reliability remains a top priority. They've got all kinds of resources coming on at the edge of the grid. It's a wild west, but in order to try and tame that wild west, we need to have long-term forecasts. It really requires that ten-year forecast.

Proportionally spreading out the forecast doesn't work, you really got to do it from the bottom up, from the edge of the grid up and that's why we really focus on that granular load forecasting. And each circuit, each feeder, each customer service transformer has different operational needs. We really focus on the edge of

the grid, focusing on those needs from the bottom up, and then understanding the DER hosting technical limits is crucial.

And that's why we look at it not only from the capacity of the system but also the power flow analysis and the limiting factors of that power flow analysis, so that we can really quantify and put in a true hosting capacity for the different types of DER.

Does this matter? So this is all great and all that we can do this, but it absolutely matters. This is an example of a feeder -- one circuit in California where if you did a traditional average avoided costs across the different customers, across the different feeders, you'd come up with a value of about $200,000 for this mix of DERs, or $300,000 excuse me. But this more granular mix and really understanding what the true value is of the DER at this particular feeder level. Excuse me, circuit level. You're going to see benefits of about 1.7, so about a 500 percent increase in benefits, if you focus down

and understand the true cost of service. Not all feeders are going to have this 500 percent difference; not all circuits are going to have this 500 percent difference. But we need to find the ones that are. And we need to target the DERs to those feeders where they're going to have the biggest impact so that we can have the least cost planning.

So I think that's, oh, one last slide here. Just in summary, determine the capacity deferral by location. We've talked about that. Quantify the power flow benefits so it's imperative to make that connection. Capture the variable side grid benefits like supply following, that's essential.

We've done projects where we've actually controlled load and response to wind, creating huge benefits for the utility. Forecasting circuit peak loads and avoiding the over averaging of the T&D. And I think this is one of the biggest ones is the over averaging of the T&D benefits. It's one that everybody kind of

recognizes today, but it's one that we've really drilled down upon.

So in summary, and I know we're running behind so I'm trying to keep us going here. We need a granular analysis to capture the full benefits of DER at the edge of the grid. It's not something that is a great idea, but we're actually implementing it. We've actually been doing this for utilities around the country. And I appreciate the opportunity to be here today to tell you about this work that we are doing and to let you know that it's not theoretical. This level of analysis is happening out there, and we encourage it to continue. Absolutely. So thank you.

MR. CENTOLELLA: Thank you very much, Bill. We're going to move right on to Michael, and we'll hold the questions until the end of the panel.

PROFESSOR CARAMANIS: Thank you for the opportunity of letting me address this group. It's an honor. So I'll have to go through the

slides a little bit faster so we can catch up on time.

The idea is to look at, I mean don't think about markets necessarily, but think about dynamic marginal costing on a location basis which is broadly construed. And which is related to multiple time scales, from their head hourly to our head five minutes. And then essentially, the real time, which leaves the realm of markets or marginal costing and approaches the physical system behavior, and that's something that is generally settled outside of markets and so on.

So what are -- my previous slide was putting a plug in as to how loads and generation has changed, or the mix of generation and the mix of loads has changed with the entrance of distributed energy resources, with the entrance of not storage quite yet, but of storage like loads, as well the prospect of storage and of the broader capability of distributed energy resources to cater to the whole basket of goods that essentially we are dealing with. They are part of

the active power in reserves. So, marginal costs that can be transformed into prices should be broadly construed and actually their major components differ to some extent as we move from high voltage distribution system, where line congestion and losses are important and where stability and desired procurement and deployment is important.

Of course at the interface of the transmission system or the distribution system at the substation level, the sub-transmission, so that interface then does exchange in the, and there must be some sort of consistency in the marginal cost and marginal value of all these products real power, the active power in reserves.

At the transmission level, most of the busses have the capability to control voltage, so voltage is not a constraint but transmission line congestion is what is important. At the distribution network, if we want to move a distribution network looking forward into sort of a big jump, where we make a qualitative change in

the way we approach things and we manage the system, there are essentially no lines. They're not hard line constraints, line flow constraints. Although, there are soft constraints which have to do with transformers for example, that we can view as a line, which has a penalty or a soft constraint associated with it. With its loss of life if we try to load it close to and above its regular capacity. Losses of course are important for they have unreactive power and because voltage control is important because we have to establish and adhere to voltage limits at multiple loads of the distribution network. Real and reactive power is very, very important, enhance the way that we model load flow and what is happening has to be more accurate. We have to deal with more precise alternating current in voltage models. And at the interface of course, the, it's important to be able to capture the response of marginal costs to transmission needs and the ability to deliver reserves to the transmission system. But this delivery is quite complex from the distribution

level. It is quite complex in the sense that, in the sense that we have to worry about voltage constraints, in addition to being able to deliver reserves.

So for example, if a particular distributed energy source or flexible load is able to promise in the market, at the market level to promise to increase its output or decrease its output as a distributive generator or do the opposite if it's a load. Right, decrease your load or increase your load and provide by the actual reserves. The ability to deliver is very much dependent on voltage (inaudible) that may come up, and hence, there's some sort of a synergy between the active power compensation and the active power offering by the same distributed energy source or other distributed energy resources that has to somehow be copasetic with the reserve offering. And the important thing is to be able to promise reserves and that can be done at the market time scale but then the actual deployment of this resource has to be done very

often in real time. If you are talking about primary reserves, there are certain flexible loads. Data centers for example can provide even, almost real time nanosecond type of response and of course at the level of regulation service. Secondary reserves can be provided.

However, in order to provide these under the contingency that, the contingencies have to be taken into consideration. For example, what if all the secondary reserves are requested by the transmission system? Will that be able to, are we going to be able to deliver this? In order to be able to deliver this we have to make sure that we offer also the appropriate reactive power response to make this possible to the extent it's possible. And if we can't, if we still can't do it at limits the amount of reserves that we can offer are going upwards.

So here we have a different type of congestion than we have here. The congestion here is hard in terms of the voltage constraints and soft in terms of transformer utilization.

Let me, in the interest of time, do I have five? About 8 minutes. Okay so in the interest of time, let me actually skip some of the details and go over. I'll tell you what these details were. These details were showing what the different costs are of the transmission distribution, what the interface is and what the additional effort in terms of modeling the network is at the distribution network. So I'm going to spare you with these details. And also they were showing how actually at the interface between the transmission and the distribution, how you can decompose, how you can relate the marginal costs at the various levels (inaudible) at the fringes of the distribution network with the location of marginal price or the marginal cost at the interface of transmission distribution. And this is very instructive, very interesting to show. Many people are talking about LMP+D, but the D sometimes can be negative. It's not always positive. All right so how do we decompose? How do the additional costs of losses that are

substantial, how the additional costs of transformer loss of life and so on during different hours adapt to the locational distribution marginal costs and how does this relate to the marginal costs.

Anyway, so here are some real results that we've obtained. So statistics of real results that we have obtained by essentially doing a computer study on an 800 BUS distribution network. Where we look at these 800 BUSs and calculate the marginal costs for real power, reactive power and reserves, at each hour during some typical day. So we've done a few typical days. I'm showing you here, of course I can't show 800 real power, reactive power and reserve prices, but I'm showing you the maximum and the minimum to make the point that the marginal cost of real power, reactive power and reserves varies by location very much, because you may have one feeder that peaks at a different time than another. Commercial feeders peak at totally different times than, as compared to residential

feeders and both of them may peak at a different time than the system peaks. Right, so you may have a very high LMP margin cost at the interface and a very low or a very high price in the same hour at a different location.

So here is the maximum and the minimum. Minimum is the blue, but you see here for real power, marginal costs, the LMPs are showing, which is the marginal cost of real power at the substation at the interface of transmission distribution, is the green and the red is the maximum.

So you can see that at the same time, right, that you can have a huge difference between real power and LMP. And that's a little bit doctored here, so that happens for example because you have locations with a lot of (inaudible) that are very close to the distribution station that are trying to push, they can't because of voltage constraints. The voltage is already quite high close to the distribution station so their marginal value is lower.

Here is the same thing for reactive power. And for reactive power you can see that the marginal cost can be quite different. So, if you try to dispatch the distributed energy resources that are capable of providing reactive power, positive or negative, through the power by putting into real use the power of electronics, then if you distribute a constant price, you're going to make things even worse. You can't just do it because at different locations the need and the value of reactive power is quite different. In some cases, you know at some BUSs it becomes negative. Which means it may be at special locations. It may desirable to actually consume reactive power in order to ease the voltage constraints. So the voltage constraint -- that's the case.

So the green again is the opportunity cost of compensating for reactive power that remains uncompensated all the way to the substation. And you have the maximum and the minimum. Here is the composition of distribution

location and marginal prices by components. So you have the LMP component which is the blue and it's quite a big component. However, the additional components that have to do with losses with transformer loss of life and voltage control et cetera are different -- the same with reactive power.

Here -- let me see, here is an example of the locational issue, and I'll probably be closing with that. So here are two BUSs BUS 689 and 619 at the same time. At one the upper voltage constraint is binding. At the other one it's not. Where the voltage constraint is binding from above, you can see that the value, the marginal cost of reactive power is negative, which indicates what, which indicates that you should consume reactive power. If you consume reactive power, right, if you try to make the current lead the voltage in order to compensate and bring down the voltage constraint then you gain. And indeed, the real power that is provided by this facility is the same, but the reactive power is of opposite

sign. So the locational component is very interesting. And here as I show the overall results, and with this slide I want to make a point that unless you do the calculation out at the fringes, you can't achieve very much. So here is the marginal cost. If everybody sees essentially an average cost or a location of marginal price, and the last column is what happens if you are able to actually do the calculation at the fringes, at each distribution network. So you can't achieve very much because you can't do voltage. You can't do reactive power compensation unless you go all the way to the end. With space conditioning for example, if you can pre-heat or pre-cool looking at the LMPs you can make some, you can have some gains, but you have even more gains if you consider the actual location of marginal prices. And with electric vehicles for example, because of reserves and the reactive power compensation, you may end up being able to essentially charge for free. The interesting thing is that distributed energy

source income, or the value you can see that it increases and particularly when you, when you do everything out at the fringes and also -- where are we? Oh, the loads, which are the people who do nothing. That's why utility commissions are very much interested in not hurting. Right, they're actually doing better. They do nothing, but they benefit because the distributed energy resources decrease the overall costs.

Okay. So, and that's something with reserves. Again the reserves vary maximum and minimum. This is what happens if you overdo it, if you over invest the market for reactive power kind of tanks, however, okay very difficult to implement. Right, because you need a lot of information and a lot of communication and so on. There is, the only way to approach this is through distributed clearing of markets and there's a methodology for doing that. It requires information. In principle it's cheap, but you have to be very careful with information architecture. You have to be very careful that

nobody goes and fiddles with this. And so the coordinated distributer approach is technically feasible, and I think it behooves us to actually try to show this, to prove this and to also study how the physical system kind of interacts with the, so the market level virtual system where the performance is important but the physics are not. So the interface between the physical system and the performance level of the system is very, very important. So there are quite a few challenging issues that can be approached and should be investigated. Right, this an empirical kind of an issue that could benefit from empirical investigation but the theory is there, right, and there is promise that it can be done. It's risky, but it can be done. You know, so we have some specific vision and methodology that could address the major issues. Thank you.

PROFESSOR DIVAN: Thank you, Paul for giving us an opportunity to come and talk out here. I'm sorry I'm going to disappoint as a professor. I don't have a single equation in my presentation.

But I'm going to talk about the physics of networks because I think when we sit down and conjure up math, we sometimes forget that it's a physical network. And there's a lot of stuff happening on the physical network that creates volatility that doesn't really allow us to do all the things we want to do sometimes. So that's kind of what I'm going to talk about.

I've spent the last four years running a start up in California. Some of the results we're showing out here are really from data that we've gathered from the field, you know, from there.

All right, so let's start with what we all agree on. We all agree that the grid is poised for some major dramatic change. I think we've had enough discussion on that. Bill had a very good session on that. We all know that the world of scheduled generation is changing. And we have significant growth occurring in a non-schedulable distributed generation. We know that we are really, you know, that's something for the future, most utilities in the U.S are still

not encountering that and not spending a lot of money on that. What they're spending money on is being more efficient operationally in terms of energy, in terms of economics. And that's where all the money is going at this point in time. You know we've seen enough cases of resiliency being an issue and you know, and everybody is focused on that and of course the threat of cyber security issues looms very large.

The challenge we have of course is that we have trillions of dollars invested in our infrastructure. So even if you came up with the best technical solution, it's not very clear that we would have a very clear path to implementing it. On the other hand, emerging markets might provide some really interesting opportunities if you want to do a re-visioning of what, you know, transmission distribution and power delivery needs to look like.

So what have we done as an industry and as a community out here? You know smart grid is, you know smart anything is better than non-smart

obviously. Right, so what our vision of smart grid has been really is, you know we have, oh all the control assets are good enough because those are really tough, so let's not worry about them. What we're going to do is we're going to bring in, you know more data. So we're going to make our assets smarter in terms of collecting, you know AMI data, voltage current data, phasor data and they're going to be very smart about massaging all that and they're going to come out with how to switch our devices better and how to manage existing control assets better. Oh and by the way, we're going to have this massive distributed kind of deployment of hundreds of thousands and millions of assets. So we've got to come up with a better acronym to manage all those things and that's the internet of things. Right? So, what the internet of things is really doing is again sensing communications, you know, and then we have so much data, there's big data analytics going on and there's predictive analytics. And they're going to take all of that information and be

smarter about how we're going to manage our asset fleet, you know, and our system so, I'm hoping that we all agree this is kind of what the course is that we've been following. And, the problem is that as we kind of look at the data that's coming from the field, we're starting to see some really big gaps beginning to emerge out here.

So I'm going to walk you through some of the data out here, if I can figure out how to operate this. So this is real data, voltage data. We had some discussion on voltage volatility and the fact that you need to know what the end customer voltage is. So, this is data from a feeder in Southern Company territory out in Georgia, and it's really showing, do any four nodes in a particular phase, you know from the substation you're going down, it's a 5 megawatt, 12 mile feeder and you're seeing the time of day varying out here. It doesn't even have solar on it, okay. And what you're beginning to see is something that doesn't track with the model that every utility uses to predict what the voltage

profile is. You know, our understanding of voltage profile is, it starts high at the substation and then goes down and there's a capacitor in between or something, and that's all kind of on the medium voltage side. This is really low voltage. This is the secondary side, and you can see that the low voltage point doesn't necessarily occur at the end of the feeders, it occurs sometime and then it doesn't occur sometime. It's varying all over the place, so you know, well the utilities say, "Well that's vendor data," so we don't believe it, right. So let's take a look at some AMI data, okay. So there's data out there from 5,446 AMI meters, very typical feeder, not a high amount of solar on it and the voltage was varying by 21 volts out there. Okay, over 30 days, and we are seeing, you know, when we talk to the utility they'll say, yeah you know one or two of our feeders might be bad and then on a particular feeder maybe 1 or 2 percent of the nodes might be kind of problematic nodes because the transformer is overloaded, a customer is not

well-behaved or whatever. Okay. What we are seeing is 15 to 20 of the nodes out here we're seeing sustained under voltages for extended periods of time. And the utility says, we don't believe the data. Oh, I'm sorry it's your data. It's not our data so you know. And we started to see more and more of this kind of thing. So the gaps are becoming really very, very visible. You know, the first thing is secondary voltage volatility. You know we've never anticipated this okay. We're seeing sustained violations that are not explained by current models. You know, if you have the SIME model, which goes all up here in substation, all the way down to the primaries of the transformer, okay well, the gaps we are seeing are across the transformer that are not fully explained by all the models that we have right now. The second thing is you know, we want to control everything with one central control lever because that whole model of centralized command and control. Well look at this, if I have one lever, I just move the whole mess up and down. I

don't really solve the specific problems that need to be solved because I need different control action at different control points at different times. We don't have the technology or the tools to give you that.

Then, we want to go and measure AMI every five minutes okay, but our capacitor banks read three times a day. Isn't there a disconnect between the two? So you really need to have dynamic control, so slow centralized control doesn't really do it okay. And so that's the other thing. So well we say smart again. Smart inverters are going to solve the world's problems correct? Because they are smart. Well, not really. Because what happens is now when you take, you know a thousand inverters and put them on a feeder and all have to do exactly the same thing, you know, maintain the voltage at a precise point. Well, they fight each other, okay. Distributor controllers interact and dynamic distributor controllers interact a lot. And so what happens is, you know, you end up trying to do

things out here to kind of make this whole thing work in some way. And what we've kind of found out is that you really need to have local autonomous control. There is no way for a utility to sit at a substation and say, this inverter needs to provide so many VARs at this point in time. It just cannot be done. And so there is a whole new way of looking at this that is possible and oh, by the way, I haven't even mentioned solar yet. Distributed energy is really the main discussion item out here and it makes everything worse, okay.

We've talked a little bit about, you know, when power is flowing backwards, you know, the voltage in the center of the BUS goes up, you know. And then, you know, you don't have much margin to kind of move. What we actually see is that voltage violations are a primary limit for how much solar it can put on the system. But even more than that, so when we talk to utilities the U.S has said, 95 percent of utilities are not making investments in solar today, but they're all

spending money on volt/var controller and volt/var benefits okay. And what we are seeing that as solar comes in, because the solar inverters are not bothered about the grid ecosystem but only by selling more inverters. What ends up happening is they just want compliance, so they want to use the entire voltage band just to be able to operate their inverters and so all the investments that you made in terms of volt/var control are suddenly out the door. You've got stranded assets out there. This is not a discussion I'm seeing that's happening a lot, and yet we are moving at 90 miles an hour on various fronts to deploy all these various technologies.

So what's the impact of grid edge volatility? So we are seeing out here that there is a high amount of volatility, and it has significant impact. So what does it really do? So you know, the fact that you have voltage varying all over the place means you can't really control it precisely. You can't move it, move it around and utilities have been spending money on

grid side demand management, this important tool okay. We are worried about energy conservation and CVR and if you've been using the distribution grid as a resource to do that, you suddenly don't have the ability to realize those benefits, okay.

We've heard a lot of discussion about technical loss and we see that loss of voltage because the reactive power drops is a major contributor to revenue lost for utilities as well. So that's a technical loss element out there. Okay so that can be improved if you can get better control okay. You really want to be able to host high levels of PV and distributed energy on the grid. And we see that the lack of grid edge control really impacts that.

We talked about micro grids a lot. Every time a micro grid has to be put on the system, the utility has to go back and do a recalculation of whether relays are invading or whether VAR currents are being managed properly or not. That's major, major you know cost and it really limits the amount of micro grids that can

be deployed. But there may be a different way of looking at how this can all be done. You know DERMS is another thing that maybe if you can't predict how much solar you can put it in at a certain point in time, what good is the DERMS package? We really need to have more predictability.

So the fact is that if you could manage your system properly, you would then be able to use your distribution grid as a predictable, dispatchable, dynamic virtual resource. And now you start seeing a lot of value that comes out of it. I'm going to show you some examples that shows that this actually can be done.

So we are really moving towards a new paradigm and I'm going to call that distributor control. It could be called grid edge control. Our paradigm today is scheduled generation, centralized top down control, planning bays, dispatch inter-directional flows, redundancy and manifest contingencies. All these things have been covered in the discussions that we've had

here to some extent or the other. And what we are moving towards is distributor control where it's nondispatchable variable, you know we call it edge up real time control. You want flexible, secure, predictable and look at what happens. If I can put the right level of control, this is real data, and I'm going to show you exactly how you end up getting that.

So we are moving from a world which is simple, scheduled and slow, very predictable, very boring, everything is good. And we want to move to a world that's complex and everybody is moving energy in every direction and everything, everybody wants to do everything right. And how do you do that? You can't go and rip this infrastructure out and put something brand new in out there, so what you have to do really is, you know kind of overly on this, and augment the performance of the existing system using grid edge elements like sensing, dynamic control, PV, wind, you know mobile energy. All of these elements sit in there and they work autonomously. They

communicate to the central to get coordination at a system level and then they communicate back with system controls to give you the kind of performance that we are talking about.

An example of this is right here. So this is an example from, that Southern company feeder we talked about. Same feeder, I've shown you this thing with top down control. And what we have really is, we have this grid edge devices, these are VAR controllers, 0-10k VAR, really small devices. They sit on the pole, and they connect on the secondary side and they figure out locally just by looking at local voltage, what VAR injection they need to do at a given point in time to manage the volatility that is there at that point. And you see that here's the VAR injection that's taking place and there is no way you can figure this out. I have no idea, you know what the individual unit is doing. It's completely autonomous in terms of what it's doing and the result is (inaudible). Yeah, so what you end up with is you have all these things that you want to

do in terms of grid edge control that we have now been able to do. And once you've been able to do that, you are able to enable a lot of the value that we're talking about. When I can move that fold, that flat foldage up and down, I essentially get demand control. So you know you can plus, minus 5 percent demand control without ever moving outside the anti-band. Okay, in some cases it can be even higher than that because utilities typically operate above that. You know, we have seen a significant reduction in technical losses and related loss to revenue. We've shown that it can advocate feeders and use it as a demand resource. And we've shown that you can increase PV hosting dramatically okay, because you're able to absorb all these issues you know locally, you're able to -- we've shown simulations with 100 percent solar loading and it works fine. In the field we've seen tremendous impact that this can actually happen.

So what are the recommendations out here? You know this kind of last light? We like

to think of the grid as an artifact. I think of the grid as an ecosystem. Okay everything is coupled, everything needs to support each other. You know, and you have a little bit of give and take and you know your body temperature is never exactly 98.4 degrees. And when things are high, things are working a little differently, when things are low, things are working a little differently. That's the same kind of thing that, that you need to have out here. So incentives to make grid connected assets really inherently grid supporting and I think you know if you can do that, that helps a lot. The grid assets should really have distributor real time control capability. I mean most the things I am talking about here -- I could see many instances of that being kind of reflected in what the grid modernization team is actually working on and that Bill was really talking about. You know when you have distributor control, we don't have the simulation tools that are there to be able to show what the system actually does. So there's a whole

kind of layer of activity that is required to be able to understand how to use distributor elements in massive numbers.

How do they interact with each other? I mean, I don't know right now that I can guarantee stability when you have a million of these devices and what happens when you have a big system level fault on some site. But it needs to be kind of proven, it needs to you know worked on. You know and finally I think if you can make the distribution grid itself a resource, then the markets can really be enabled once you are at that point. It can become very, very predictable. So overall, that's what I want to say, thank you very much.

MS. SANDERS: Wow, that was some serious energy. My three-hour time zone change may not lend itself to that level, but we'll see. And being the fourth speaker there's not much more to say, I'm sure you're all very clear on how we value DERs and what the value of DERs to our electric system is, so I'm just going to be done.

So just putting this DER valuation in context in California, a lot of you know this already, it's great to be in California. We have lots of opportunities to do lots of things, and we have to figure it out very quickly. So AB327 required all utilities to submit what was known as a distribution resource plan by last July, which we did. Part of this included doing many things, but in integrated capacity analysis which looked at the current system and said this is how much you can install with no upgrades. And then also do a locational net benefit analysis that gives us an indication of where DERs are more or less valuable on the system. We said sure, piece of cake.

So if you look on the left hand side of this, the guidance given by our Public Utilities Commission included a number of values that DERs could provide. Energy losses, generation capacity, ancillary services, transmission capacity, distribution capacity, environment, avoided renewable portfolio standard energy

requirement. I was going to say RPS but I thought I would spell it out. And then additional components which just could be anything.

So you start to think about that and the first thing is, can all of this happen at once? And the answer is no. If you are going to be a transmission asset and provide an ancillary service, and you are going to be activated for contingency, guess what, you need to be there when that happens and you don't know when it's going to happen. I'll tell you, moving from transmission to distribution has been very enlightening. Transmission is awesome. You can forecast; you can plan; you can see it. Distribution is crazy. It's crazy out there. I went out there with a troubleman because I wanted to see how crazy it was, and oh my gosh, and when we've got three phase, single phase radial, we've got stuff underground. We've got lines for miles. It's amazing. So when you talk about this value, it depends. So we have worked on this, and we offered up in our DRP, you know how you can value

this and since I'm in electric system planning I want to really focus on the value from the distribution perspective.

The first thing that has to be examined is our process for distribution planning. So Bill talked a lot about forecasting. I have to say that's probably the most, or one of the most important things we need to do better. It needs to be more granular in location and it needs to be more granular in time. Because it matters where you put these DERs and how they function, we need to do that a lot better. We need to be able to not only do it for load but we also need to be able to do it for every resource type that's down there and we need to do it pretty well. Because that planning assumption drives everything else. It drives what we build. It drives how we operate. It drives everything else. So without that forecast being pretty, pretty accurate -- so in transmission we can have good forecasting accuracy. I never thought it was that good, but it kind of evens out at the end and you can build

pretty well.

One of the challenges we have even now, before all the DERs were out there, is we do a distribution plan every year, for load growth, every year. So we forecast for our different regions, we have 4 regions and 32 districts and we do very granular forecasting right now for that peak. That distribution resource plan results in, it's about 1,900 pages, it's very exciting reading and hundreds and hundreds of distribution projects, hundreds.

We do the same thing and guess what? Many of the things we forecasted out as a need in ten years go away. Or they come in five years. So that's because not only are the forecasts not accurate to begin with, but people did different things. Stuff happened. Businesses moved in, businesses moved out, stuff happened. Distribution planning is an art more than a science.

And so this is one of the things I want to really think about when we're talking about

assigning a value to these. So we do a forecast, we determine a need. Then we go through a screening process. So one of the things at Edison that we believe makes sense and want to, you know, get moving in the Commission is this notion of a screening or a deferral framework. We have hundreds of projects. Some of these things you just need to build. Because they make sense, they're short term, you know, they're -- you just need to build them. Hundreds and hundreds of projects shouldn't be litigated in front of the PUC to be replaced with DER.

So right now we are suggesting a very loose screen so most everything falls through. And those projects get an opportunity. This is the first place where valuing DER matters. So right here you need to think about what would it cost us to build that infrastructure as a baseline? Now, those methods are done usually through a voided cost calculator and there's all these spreadsheets and all of this. But at this point it's really more benchmark to compare to

your DER solution.

One of the other things that's really dangerous is publishing that number. Because guess what? Your DER solutions are going to cost you that much. Even if it doesn't cost that much to build them. So we're stuck in this time where there's all this opportunity for technology to come in and solve the problem. They want to maximize the money they can get. So, okay, utility, tell us what it costs you not to build it, and we'll take all that money. And we're saying, well, but if you can do it cheaper, you know, why don't you and then we return that value to the customer. That's what we're saying.

So you get these projects that fall out of this screening framework. Then you determine the operational requirements, and then the attributes that these DER's need to have in order to replace this infrastructure solution.

One of the other things that we need is an equivalence study or an equivalence discussion and pilot. What I mean by that is, if we're going

to build infrastructure or we're getting a project that comes -- tell me if I need to yield the floor to more important individuals.

CHAIRMAN COWART: You're doing fine.

MS. SANDERS: Okay.

CHAIRMAN COWART: Keep going.

MS. SANDERS: So when we think about replacing infrastructure with a DER, those solutions are not equivalent. They're just not. They're different. DERs can provide you more operational flexibility than a capacitor bank. You know, you said they operate three times a day. Well, I had to phone a friend. That's what I love about text messaging. So I phoned a friend. Apparently ours switch twice a day, but we will allow them to switch up to eight times a day. But otherwise, you just decrease their life so much. So we only switch those just a few times a day. So DER's can bring you more operational flexibility.

But the other problem is, is are they available when you need them? Are they

dependable? Do they perform how you need them to? And are they durable? Are they always going to be there? When we put an asset out there, if we put a piece of infrastructure out there, we know it's always available because that's what it was put there for. We know that it's dependable. We have characteristics even if we don't actually believe the vendor data. We operate them. We know how they generally work. And then they're there for their life.

So one of the things I think is really needed is to say, here's a list of traditional infrastructure upgrades. Whether it's anything from building a substation to upgrading transformers to reconductoring to adding circuits, whatever it is, I would like to understand what DER or combination of DERs could do that too, and what do you get and what don't you get with that? And then foundationally, how do you realize it? So this is the next piece is to then pilot that equivalence and make sure it actually does what we expected it to do.

The last step of this from our perspective really gets down to that other valuing of DER. So what we don't do and what we don't spend on infrastructure isn't what you pay for. What you do is you go out and you get competitive solicitations to do price discovery. We have had great success in two of our RFPs. One, our local capacity resource RFP where we procured a lot of storage, and one in our preferred resource pilot. So we're seeing the technology, we're seeing it be competitive, and we believe that's the best way to value this, what you pay for it.

So these are the process as we see it evolving. Now just as an illustration, we do planning right now, and this was a need that was identified in our Merced area for -- a need for five MBA. So first thing you do in planning is you see if you can shift it somewhere else. So this is what we do. We look at all of our associations around there and all our circuits and see if we can permanently move it somewhere else.

And in this case, if there's enough

there, we move it someplace else. Now, we're able then to have that loading relief. Now let's say that we want to satisfy that with DERs. Now because of their operation and so forth, it may not be five, it may be more. So we just need to think about locationally wherever those show up, they may need to be more or less. And this is why I think it's important when we do this discussion about, you know, what's an equivalent solution. We put in all the "it depends". So if I put DERs, you know, at the end of a line versus I put them in the load center, they can do different things and they can offset a different infrastructure.

I said this before on the other side about the competitive procurement. It's really the value of them is to compare the total cost of the solution, so that benchmark that we as the utility would have spent. So historically, we can give a range for what it costs to build a substation or what it costs to build a new circuit. And it's going to depend. We've got some pretty crazy terrain in California. We've

got some awesome environmental licensing requirements. So they cost different depending on -- it depends -- where they are, how long they are, et cetera. But there's a range of that value that can go out there that can then be compared with the DER competitive solution. And that determines the value.

So we really underscore at that point then is you've got to be able to realize this value. We have this automagical leap that we're making right now in the discussion of DERs can replace infrastructure. And we heard it here and we saw it on a slide. If you dispatch demand response and energy storage and other DERs, they can do this. They can. But I haven't seen it work yet.

And the other thing that's important is grid investment is still needed. Even if we don't build the infrastructure, we've got to be able to monitor these things.

On my right, along with the troubleman, who was talking about a situation where we need to

switch -- we switch every day, thousands of times a year. So when I say we switch, we're basically transferring load onto different circuits whether it's for maintenance or car hit pole. Car hit pole almost every day, and Mylar balloons get trapped in lines or substations almost every day. So we perform switching operations all the time. So your topology of your network is continuously changing.

So I was out with this troubleman and he is talking to me, because I'm trying to really understand what this means, so I'm out there and he's telling me, "Well, yeah, I had to switch this load to a different circuit. It was reading 200 amps. I got this other one, 200 amps, it's good for 450. I'm just going to shift it over there." As soon as he performed the switching, this one overloaded and tripped out. Why? Because there's really 350 amps on here and a lot of it was being served by solar. When that switched, it didn't take the generation with it. So they didn't know because we didn't have the monitoring, we didn't

have the analytics to let them know what was going on. And we didn't then have any sort of ability for him to be able to make that operation and not drop more load. So there are some real examples out there of, you know, just operationally what you need to be able to do.

So one last thing is the -- our distribution resource plan is riveting. I recommend reading all 500 pages. It's awesome. Carl's read it at least three times. But what I really do encourage you to do is look at our distributed energy resource interconnection map. And when you open it up, you're going to see every single circuit. We have 4600 circuits in Edison territory. You're going to see every single circuit. And it's going to show how much integration capacity is on that circuit now from a generation perspective, so a supply perspective, and from a load perspective. And so, you know, if you know anyone there, you can follow their circuit along. My particular circuit can take 3.5 megawatts of solar. But only .87 megawatts of

load.

So this is where we're needing to go in the future. We need this visibility, we need the monitoring, we need the control, we need this investment. But most importantly, where we are now, is we need the messaging. We need to really know and believe that DERs can replace infrastructure. We as engineers need to believe it. We as troublemen need to believe it. And then we get policies that actually make the right outcome happen.

So thank you so much for your time.

CHAIRMAN COWART: I have to say, those presentations were awesome. You have really got me going. And I'm going to apologize because I know that the members of the Committee would love to follow on immediately with you with Q and A. But we have the honor of having with us Commissioner LaFleur, who stepped out just temporarily because of the fact that some matters were being touched on that we're involved in pending proceedings. But she's right outside and

will come right back in to join us.

So what we're going to do is hear from the commissioner, and then we will have a robust discussion period on the topics that this panel has touched on. So I want to encourage members to write down your questions and remember what it is you want to ask these people. And in particular I want to ask Professor Caramanis to bring the printouts of those slides he skipped over so that we can discuss them over drinks, you know, as we're having dinner.

Commissioner LaFleur, would you like to sit here? You can have this chair or you can stand at the lectern. Okay. No, that's fine.

COMMISSIONER LAFLEUR: Thank you.

CHAIRMAN COWART: As just about all the members of this Committee know, Cheryl LaFleur has been a sort of a de facto member of this Committee for quite some time. And she's been -- she has visited with us on numerous occasions and spent a fair amount of time in this room with us. And we have the honor now of having her back as a

presenter. And I will tell you that we -- this won't surprise you, that she very politely asked us what it is that we want her to talk about, and we very politely answered by saying, "Commissioner, what do you want to talk about? And I think that you know very well what topics interest the Committee." And we gave her free rein to come and speak with us about the issues of concern to her that also she figured would be of interest to us.

So I'm just going to turn it over to Commissioner LaFleur.

COMMISSIONER LAFLEUR: Thank you very much, Richard. I'm happy to be back with the group. I had been sort of liaison to this group for a couple years and then didn't come as much during the period of time I was chairman, sent representatives, and I'm really happy to be back. And I've never had a higher honor than to be called Sonny Popowsky, the father of the hybrid cost allocation in PJM.

I have with me, somewhere, Andy

Weinstein from my office, who is one of my -- I'm sure all of you people who work closely with FERC each commissioner has three advisors, and in my office Andy does ISO New England, New York ISO, gas LNG certificates, and some rates as well as enforcement. So that's quite a lot.

I also just want to explain that the reason I'm wearing a T-shirt is I had a Bloomberg interview a couple weeks ago and they were asking me about wearing New England and Boston sports clothing to open meeting. And I said I had never worn Celtics stuff, but I realized because it was St. Patrick's Day. To the best of my memory, the first open meeting on St. Patrick's Day since I've been at the Commission, I think that makes sense because I haven't been there seven years, so I thought this was a good time to remedy that.

What I'm going to do is just kind of do a snapshot of some of the things that are -- or an overview of some of the things that we're working on at the Commission with respect to electricity, hopefully to tee up questions or at least sort of

highlight areas that might be of interest.

I almost never bring any charts for all kinds of reasons, mostly that I never have time to do them and time for when they're due. But also because then you get into all kinds of torments of what you put on the charts and whether it's ex parte and how detailed. But this morning at open meeting the Division of Energy Market Oversight did their annual state of the markets. And it's really I think quite a good overview that gives some evidentiary support to a lot of the things I'm saying. So for that reason I'll pass it out. Of course it's also on the FERC website. So if you don't want to carry it on the plane, it's a public document, just junk it anywhere, but here it is in the meantime. I've been many times having carrying like draft orders and, you know, wondering if I can possibly put them in like the ladies' room, the bathroom trash of an airport, being too afraid. But these are public, so you don't have to worry about any of that.

Okay. Of course anyone who's heard

anyone speak, I speak only for myself, not for the Commission. I will try very hard not to discuss pending adjudicated cases, and that's why Andy and I walked out. I walked in, I was doing my email, everything was delightful. I looked up and realized they were talking about DERP in California, which has been pending before the Commission for a couple weeks, and thought, "Oh, they're talking about DERP." And so I belatedly walked out.

It's no surprise to anyone in this group that follows energy so closely that a lot of the work at the Commission right now, just like a lot of the work at the state levels, is really being driven by changes in the energy resource mix across the nation. You know, driven really by the great abundance and affordability -- some would say too much affordability -- of domestic natural gas, the growth of renewables and demand site technologies, all kinds of new technologies, powered by state and federal and tax policy, as well as new environmental regulations. The clean

power plan is on hold, but (inaudible). Many other environmental rules that are leading to a lot of turnover in the fleet are very much in play. And that transformation is really driving a lot of our work on the market side as well as on the infrastructure side of our work.

Starting with the markets, just a couple points to make. The first is that despite all the challenges that market seemingly perennially face, they continue to grow. I was at Harvard Electricity Policy Group a couple of years ago and got into a little bit of a tussle with Bill Hogan, which is really not something you ever want to do, about whether markets were growing. And he said, "Well, they're just growing along the edges, they're not growing organically." Well, whatever that means. But I would say now they really are over the last few years growing. Because the Mid-Continent ISO, which used to be called the Midwest ISO, almost doubled its size by adding all the southern states, Mississippi, Louisiana, Texas, and part of Arkansas with Entergy and all their

appendages. And more recently, last year, the Southwest Power Pool added parts of six states going all the way up into the Dakotas with the integrated system, including the first time a federal power marketing administration joined a market, which I thought was highly significant. We had to tie ourselves a little bit in knots on the cost allocation with how we were going to pay for transmission to accommodate a federal PMA that is not under FERC jurisdiction. But SPP brought us a proposal we could approve, and now the Western Area Power Administration, a big piece of it is now in a market creating energy in the market, planning transmission with the market for the first time.

And of course biggest of all are the changes that are going on in the west with -- I'm going to actually put on my glasses for this -- so far two companies, both part of Berkshire Hathaway, PacifiCorp and Nevada Energy, have joined the California ISO energy and balance market, representing 3.1 million customers across

six states. And they've already saved nearly $50 million in the first 13 months of operation just by balancing the wealth of renewable resources and other resources out there around a bigger platform spanning time zones, different diversity of resources, diversity of loads, and just tremendous more potential savings for customers to reap.

Since that time, four more companies, Arizona Public Service, Puget Sound, Portland General, and Idaho Power, have either announced that they're planning to joint or they are pursuing joining. And then rumors continue to abound of more companies out west that are looking into this, potentially adding another 3.5 million customers. Should this come about, this would really bring a market to the west that was planned before the California energy crisis and kind of got derailed. And that's the part of the country that really has just abundant renewable resources, long stability balance lines, and lots of potential for working together. So we're working on that, trying to work through the cases

carefully, trying to learn from the lessons as one joints for the next one, and really looking at a lot of potential benefits.

Then that was barely taken on board when PacifiCorp took the next step and announced they were exploring joining the California ISO actually as a participating transmission owner. Not just the imbalance market, but really jumping all the way in and becoming part of the market. And as most of you probably know, last year the California legislature passed a law asking the California ISO and others to come back with a proposal for how they would change governance to make the California ISO a multi-state ISO. Because it's very much a California governance organization with the board members appointed by the governor. Now they face potentially an independent board, a multi-state organization with some sort of an advisory Committee like a lot of the other ISOs have. Really looking as a model to the Midwestern ISOs that have vertically integrated companies underneath and state resource

adequacy programs, but markets manage at a wholesale level. And PacifiCorp and California ISO are well on their way to exploring that, and we are trying to I always say send them positive vibes without making it a FERC project. Because I think the more it looks like it's coming from Washington, the more it'll look less like it's coming organically from the region. But that could potentially really change how things are done in the west.

So while markets are growing, I mean if that all comes about, it'll really be the southeast that's the last bastion of fully vertically integrated. But even there transmission planning is starting to be done regionally. And, you know, we're just seeing more regional cooperation everywhere.

So that's great, markets are growing. At the same time, I think it's no secret to anyone who lives in them, I'm looking at Gordon and others around the room that the markets are being stress tested right now. We're in a fundamentally

different time than when the markets started, you know, 20 years ago or so when everyone was long on resources. They were pulling the efficiencies out of the markets. You know, had very high reserve margins, figuring out a way to run things more efficiently over a big geographic platform. Now, for all kinds of reasons, the low gas prices, the environmental requirements, natural aging of the fleet, we're seeing a tremendous amount of retirement really everywhere, certainly in the eastern markets, meaning that the capacity markets are doing their job and calling for new resources with high prices. Harder to support markets when they're costing more than when they're costing less. And the markets are really being tested to make sure that they can attract the resources, that this idea that you don't need an obligation to serve and you can use a market to bring in resources to serve customers. It's really on the firing line right now to make sure it really works. And, you know, we've seen a lot of capacity be offered into the PJM and ISO New

England capacity markets in the last couple cycles and really looking closely at those as that comes about.

I was going to say something else and I lost my train of thought.

What we've seen is that as we're in a period of an investment cycle, we've seen a lot of the RTO's look at their markets and make sure they're properly defining the product that they're buying and made some changes in first ISO New England and then PJM. That really changed the definition of the product they were buying to have higher performance requirements and make sure they were fully compensating the reliability value of the base load and other things that you could count on when you needed them. That was -- that's a pretty fundamental change, I think, to the capacity markets, and we're just seeing those run for the first time in a full year. And that's a pretty significant change that we're now seeing go forward.

On the energy markets, FERC has been

working for a while on a so-called price formation effort, really to look across all the things it takes to keep the lights on and to make sure that as much as possible those are included in the wholesale energy price, the marginal price, rather than paid out the backdoor in uplift or special out-of-market operator actions or any other way to make sure that the energy market price that people look for an investment signal, that people look for to decide how to use energy properly sets what it costs to keep the lights on. We've taken some steps over the last several months, and right now we had required the six RTO's that we regulate to come in with a host of homework on what they're doing on different issues. Those are out for comment right now, I believe, and we'll be looking at next steps to try to work on uplift and some of the other aspects of price formation. What we found when we really pealed the onion and started looking at it was that this wasn't something where you could put out a simple rule and say, "Do it this way everywhere." It was very much tied to

how different markets were designed, and we really had to get into it, you know, in order to start really making rules. But it's something we're committed to, came up again at open meeting today. It's going to be a major effort over the next several months.

Another thing to mention about the markets kind of relates to all of what I've said so far, is that as we see the resource mix changing -- and this is teed up a little bit in the charts that I handed out -- is we're really starting to think hard, and the markets, the RTO's, the market operators, are starting to think hard, and NERC and others, on what are the products, what are the increments that we need to really keep the lights on? I mean I say when I was young and first in the business, you just bought electricity. Maybe if you were really getting creative you thought of capacity and energy. That was about as much. I at least never talked about Black Start and reactive power. I knew there was a thing called reactive power. The thought

that it would be compensated separately was just not something I could even get my head around. But now, as a lot of the spinning base load, you know, the synchronous motors are coming offline or being used a lot less often or being turned from base load into cycling, and all of the above, and we have a lot more of the energy coming from renewable resources that are not synchronous, that are not controlled by a man or a woman setting a switch but are controlled by the availability of the resource. We're seeing the need -- really thinking hard about the need for frequency regulation, frequency response, voltage support, Black Start, ride through, ramping. Something they're doing a lot of work on in California.

And if you look out at a market and say, "Gee, if our resource mix changes from A to B, we might need more of this increment." There's two ways to get it. One is to say, "Well, gee, maybe we'll just go order people to go buy that." But if you're really committed to a market, the more honest way to do it is to say, "Well, define what

it is we need and see if we can use a market to price it and we'll see how that works." And we're seeing that more and more. We've put out several orders in the last several months looking at how to get primary frequency, primary frequency response and other increments that the market needs to see if we can price those as ancillary services going forward.

This is not in a particularly logical order, but it seems like the right time. Rich asked me to mention Order 745, Demand Response. That was an example of defining a capability. In that case, the capability to ramp up and down at peak to keep the lights on, to ramp the power up and down in a way that was economic for customers through, in this case, the use of demand response to reduce the load when it was most expensive. I'm sure folks know that several months ago the Supreme Court reversed the DC Circuit and upheld the Commission's Order 745 from 2011 that required RTO's to compensate demand response in a way that we thought was fair, similar to generation.

Because unlike the clean power plan, Order 745 had never been stayed, on the service nothing changes.

I tend to think that the cloud of the judicial review had some effect on the demand response market and we'll see how it develops going forward. But that's an example of defining a capability, I know it was controversial one, but it's an example of a way to define what we need and let the market value it.

Looking ahead as, I'm really unsure because I don't have a crystal ball, how long the investment cycle that we're in now will last but I do see as long as the technological change continues that we will continue to see changes in the market. It's been kind of axiomatic that most resources get most of their money from energy, maybe a hunk from capacity by buying you know some kind of reservation that you pay ahead to have something online and little bits, little extras from ancillary services. In the future we may be paying more of our fossil units in some parts of the country to sit around and be there when the

sun goes down or when the wind stops blowing and that might require a different way of structuring the payment stream and a different way about thinking about the base load if we want it to be there. And we're just really early in that evolution of really thinking about you know, how we pay resources in the future. I don't think it will be how we paid them in the past if we see the resource mix continue to change the way it seems certain to.

The second thing that really is, the second big piece of our work at FERC besides markets is infrastructure. Starting with transmission, we're believe it or not, it's been almost five years since Order 1000 was voted out requiring certain changes to regional planning and cost allocation and some interregional coordination of transmission planning. I hope it has had a positive impact, I think in many ways the impact is just starting as we start to see the first competitive processes happen and I realize it's been an enormous amount of work on the part

of the folks all around the country that are working to make it a reality. And I think appropriately we're taking some, putting in some effort to see how it's working. So this morning at open meeting we heard a presentation on something that was teed up about a year ago on transmission metrics, starting to get together a set of metrics on how much transmission is getting built, what's it costing, how is, how are competitive processes working, are, is congestion going up or going down, when do prices separate. I'm almost certain we don't have the perfect metrics I don't think anyone ever put out a set of metrics and got it right the first time but try to start thinking about how do you measure whether we're getting the transmission we need and is Order 1000 having a positive impact, is it working, do we have to make changes, and so we'll be tracking that going forward. And this morning at open meeting it was announced that in late June we're going to have a one and a half day tech conference, there's almost not enough coffee for a

one and a half day tech conference on Order 1000. Which is actually I believe, like butts up against the PURPA tech conference so it will be like a tech conference week the last week of June, they're all adjacent to each other. But one of the things that we're going to be digging into is how competitive processes are working and what if anything we might need to look at in our transmission rate making and incentives. For, I don't know how closely people, nobody's sitting around reading all the FERC filings all day long but over the last few months we've gotten a lot of proposals for different ways for people to charge for transmission, or different kind of incentives or security that they weren't, that they want built into their rate because of offers that they make in competitive transmission solicitations. So people saying, "Hey I gave a cost guarantee that I wouldn't go above a certain amount for the entire life of the project, I want mobile sierra protection for that so it can't be changed," or "I built a cost containment and I need an incentive

for a little bit more ROE in exchange for the cost containment" and we have in the orders that we put out, said we're not going to just decide this one op, this requires a little bit of thought because it's really a change in the way transmission is priced and if there are changes that have to be made in transmission rate making to make competitive processes work we should think pretty hard about that and that's part of what we're going to do at that session in June and potentially look at other parts of Order 1000 how its working because we've seen some the RTOs come in and say "Hey we're getting some proposals that have one set of cost guarantees with (inaudible), we got other sets of proposals that have no cost guarantees, we have other proposals that have just construction cost guarantees." This is not something we've not normally done is do a lot of cost comparison, how are we supposed to evaluate these fairly so that we don't get into a litigation loop and again we're trying to add value here not make things harder so I think that

(inaudible) is thinking about before we start deciding them one at a time.

If there's anything else to say about transmission -- I know this is the Electricity Advisory Committee but bearing in mind that a lot of electricity these days is made with gas more and more. The second part of our infrastructure work is pipelines and LNG. That is becoming a lot harder not easier. First of all we have a lot of a lot applications that should surprise no one given that gas is coming from places it didn't come from before so the pipeline structure that existed prior to the advent of hydraulic fracture and shale gas is not the pipeline structure you need in the world of where the gas is being supplied now but in addition a lot of the gas is being used for generation rather than the pipelines being mostly built for the gas distribution companies and so therefore, we're seeing a lot of proposals to build new pipelines. In some cases to support electric reliability. I don't think it would be a secret to anyone that

we've seen a tremendous amount of opposition to the use of natural gas as a fuel for generation, particularly I would say in the North East, generally defined. We had a large group of protestors at open meeting today. I'm hoping that never becomes something we just kind of don't even notice because it happens every time. Although it has been happening for about the last two years and a tremendous amount of opposition to building pipelines. Both the normal or to be expected concerns of people who live close to whatever infrastructure is going up, that's been always the case, it's certainly just as much the case now if not more but also, a real national debate about whether we should be using fossil fuels at all or whether we should not build anymore fossil fuel infrastructure as some groups think so that we could transition to something else. And although FERC does not regulate fracking nor is the tsar of how we get our energy, we are the very much the full (inaudible) of where a lot of those protests and debates are being felt and we are working as

hard as we can to understand our responsibilities under the National Environmental Policy Act, to understand how we decide public interest in a pipeline, how we should do that, how we make the best decisions but it is getting to be both volumetrically and in terms of intensity a hard area of our work. Looking at Gordon and other people, the pipeline proposals, they're there for a reason, there are constraints in the pipeline network and there's a reason a lot of these pipelines are being proposed.

Just want to turn quickly to reliability, something I talked a lot about when I use to come to this group all the time. It's been ten years since the Energy Policy Act almost, ten years since the Energy Policy Act was passed or, no more than ten years, ten years last summer and FERC got the reliability authority. I was on the other side of the table for the first couple of those years then nowhere for a few years and on this side of the table. I would say the first, I'm looking at Marc, the first five years were

getting our act together, who did what, how you wrote standards and really codifying a lot of the basics, a lot of the relays and tree trimming and the things that were codifying how you ran an electric grid. Over the last maybe two to three years a lot more of the action has been around emerging issues, cyber security, physical security, I'm not sure that's emerging it always existed but it's been of high visibility recently, geomagnetic disturbances and solar storms. We're a lot less energy around you know how often do you trim your trees and more around some of the emerging issues and the pace of how we do the standards, you know where we iden -- either the industry comes forward with a standards application request or NERC makes a proposal or FERC says we see a need and orders a standard to be done and then the Committee is put together and the standard is put together and it's voted upon and it's submitted and we do an order and we put it out for comment and we do another order. That pace while well suited to careful deliberation on

what the standard should be, is definitely not well suited to say Ransomware was invented last week let’s fight it now. It, you just can't make a standard in time for some of the emerging cyber threats, so it's something we have to think about. I think the standards are becoming kind of what's the basic framework of good hygiene and the rest of the work is done voluntarily or in information sharing forums or otherwise. I know we got a, congress passed some legislation at the end of the year intended to promote information sharing, give us a Freedom of Information Act exemption from, for critical energy infrastructure, give the depart- Secretary of Energy emergency authority. That's all very positive in my view but in the mean time we try to make the standards as robust as we can so they can be a basic protection that's out there and we are on the sixth generation of cyber standards taking effect in July. For the first time something covering every bit of the bulk electric system, those are I know engendering a lot of work right now for people to get ready to

have the compliance deadline happen. The one loose end hanging from our order on cyber was supply issues. We wrote a couple pages in our order last fall saying, "Hey it looks like a lot of the cyber threats are coming through supply chain," things that people buy that might have malware or something in them and we want to think about if there's anything we should do with standards that would address that. To say that's been controversial is an understatement, we-I certainly know that we do not have jurisdiction over everyone that makes a piece of software or a piece of hardware but we're thinking about if there are sensible rules we can put out for the people we do have jurisdiction over. If there's value we can add or if it's already covered by NIST and (inaudible) and other folks and that's a work of- in progress right now. A couple weeks ago we held a tech conference on geomagnetic disturbances. The ball's in our court now to put out a final rule and we get that in place.

Final thing that Rich asked me to talk

about, relates to reliability is the clean power plan and how FERC is engaged on that. So, I think it's obvious but I think I keep saying it, we do not make environmental rules. The EPA and state environmental regulators make environmental rules but they have a big impact on the part of the world we do regulate which is the electric grid and it's in part our responsibility to make sure reliability is sustained as the rules come in play, come into effect. I think that has worked fairly well with the mercury and air toxics rule, the EPA wrote a provision into the final rule that provided an opportunity to get a little more time if needed and gave FERC the and others NERC and the RTOs and the states the ability to be advisory bodies to EPA on whether more time was needed. We've had four or five folks come in and ask for more time and I think we have usually concluded you know by either looking at the NERC standards or their resource margins or whatever that they had a good argument and passed that along to EPA. That seemed like a big, big accomplishment when we

worked that out but it seems like child's play compared to the complexity of the Clean Power Plan with all the states coming up with their proposals and figuring out how they weave together. Of course the Clean Power Plan was stayed several months ago, these, most of you probably know better than me but I'm hearing that many of the states are still thinking about what they might do. The work has not stopped because at such time as the stay is lifted and the deadlines potentially kick back in it will be a significant undertaking. Every study I've seen has said doing things regionally is cheaper than doing things individually, that's kind of a no brainer but it's not straight forward with some states being, choosing mass based, and some being rate based and some people saying they're smart enough to figure out translate them and other people saying no you're not smart to figure out how to translate them. I know I'm not smart enough but hopefully there will be a way for people to collaborate even if they have different structures. We had, FERC

staff had signed an agreement with the EPA and DOE back around the time the Clean Power Plan went final that we'd meet at least quarterly and talk about challenges and hot spots and what we should be doing. I believe those meetings are still going forward although honestly, they're thinking about how do best work now during this period and we've been doing some outreach to the industry and others. I know look around the table some of you are the folks to whom our folks reached out to figure out where things are so we stand ready to, to work on it but we're a little bit in the period of waiting to see what happens. But even though the Clean Power Plan is stayed at the time when it was proposed I'd said what we're going to have to do with the Clean Power Plan is really three fold: Make the markets work, make the infrastructure work for the new resources and then any kind of coordination with the EPA we have to do. Well the third part is kind of on hold while we figure out what the rule is but the first two are going forward even though the rule is stayed the

transition to clean energy is anything but stayed. I mean the, the beat goes on we see more and more states pass different renewable standards, pass different rules and in fact that's the last thing I forgot to mention and then I'll take questions is that a significant emerging issue is how wholesale markets interface with state energy policies. Different markets have made different accommodations for state renewable standards and so forth. Yet there is a sense that if you're in a wholesale marker fundamentally the market is supposed to be choosing the resources so I can't talk about some of the things going on in Ohio and elsewhere because they're all pending but this issue of how states and markets work together is not going to go away. Change is happening for everyone and you know markets are only going to work in the long run if they have the buy in of the states that are parts of them and we'll have to figure out you know how make that work. I think that's going to be a big piece of the work at the commission going forward.

So with that happy ending of an insoluble problem, I will be happy to stop. I think I about stayed on time and take questions or whatever you want to do next. Thanks. And kind of an overview of everything so that no matter what you want to talk about it it's somehow related to something, or if it's not then just ask anyway.

CHAIRMAN COWART: Questions for the commissioner. All right, Gordon.

MR. VAN WELIE: Cheryl, you did a fantastic job doing an advertisement for a panel that we're going to have tomorrow morning which I teed up because it's the same problem that you know I'm worried about. So I'm not going to ask you about that question that was just an advertisement for everybody for tomorrow, to remember the discussion in the last five minutes. But I wanted to raise another issue with you which is sort of the next stage of the, the discussion that I'm also worrying and I mentioned it earlier on. Which is, you know the sort of the first to

mention to the intersection of public policy with wholesale markets is this renewable energy issue and how does that effect the market and so forth but I think the next stage of this which is coming quite rapidly is what's happening the meter with regard to distributed resources and so there's a jurisdictional split there so you have, if we have situation where we have a hybrid grid in the future where, I'll just make this number up 70 percent, 60 percent of the resources coming from a grid scale resources and is subject to FERC jurisdiction and the wholesale market incentives and as you pointed out we've taken great strides with regard to tightening up product definitions and so forth but 30 or 40 percent is coming from behind the behind the meter is being contracted for in a completely different manner and is not necessarily seeing the same incentive system and doesn't have the same operational accountability. It's outside of NERC jurisdiction for example and yet we have to rely on the whole to perform at the right moment. How do we achieve that? And so I

think it's another sort of insoluble problem that I'm, that I'm fretting about.

COMISSIONER LEFLEUR: Well it's certainly a good question. At open meeting today we, they did the state of the market report and every questions no matter how they were churning inside they said, "Oh thank you commissioner for that excellent question," you know before they started kind of gritting their teeth and answering it. I think the, at the highest level of generality the constitution and the idea this is what the Federal government and this is what the States do has not kept up with technology and you see things that are done behind the meter that begin to look an awful lot functionally like things that are done at a wholesale level and you know the, I've said frequently it's not so much that we're trying to reach behind the meter it's that the technology is starting to blur or what's distribution and what's transmission and what's generation. At the most straightforward level as you know Gordon what's happened thus far is some

of the early skirmishes had been around how do you count what's behind the meter, do you account, how do you account for solar, how much do you buy, what do you count is going to be there. It started with energy efficiency now it’s around a lot of the roof top solar. Grand Scheme that's a fairly simple question although not necessarily an easy answer. In term of the behind the meter generation the, the policy of FERC, the precedent right now is that as long as the relationship between the customer and the distribution company is a net sale, meaning that on balance at the end of the billing period the company sells more than they buy back from the customer, it will still be considered retail rather than a wholesale sale. What we're seeing is that those lines are blurring as some states are putting in net metering that has no true up, an annual true up a forever true up, community solar that if you look at it quickly it begins to look like a qualifying facility under PURPA and I think it's inevitable that we're going to have to wrestle with is in a different way than

we did before. It's not a battle that we're like rolling up our sleeves and saying, "Oh we can't wait to dive into this," but realistically we're hearing a lot about people questioning where community solar or some kind of sort of central station distribution level resource ends and some kind of wholesale PURPA machine starts and where that all, and so I think it, that is ahead. I mean clearly these are all resources that we should have on the system and there's got to be a way to take them in but it's going to require some real adjustments with the way we think about things from, it's just another adjustment. You know we use to think about got the power plant, you put an hour or so from the city, you build a wire, extension cord to the person next door you know then you have your, you pay on peak. I mean that's the way everyone understood the system. Now so much has changed, I remember the first independent power producer, I had engineers in my office saying the lights may go out, we can't hook up to them and now it's just taken for granted.

This going to be another thing that maybe in the future we'll take for granted that you can have things on the distribution level but it seems like a brave new world right and we have a lot to work through.

I must have done a good job, there's like six more cards, so.

MR. BROWN: Merwin Brown, CIEE. In your remarks you, you mentioned something about having to pay, I'll call them stand by conventional generators for when the sun goes down and the wind doesn't blow. How about the opposite of when there's too much of that going on and you begin to have to because of must take situations policy contracts or even markets saying you should take solar or wind first. How about the similar situation where you're going to have to pay to have the capacity there for stability reasons. So anyway is that in the cards too?

COMMISSIONER LAFLEUR: I mean yes, I think that's right, I think first of all we're seeing more negative pricing which is another one of those

things it's like, "Negative pricing, what's that?" But I mean at some point you have more than you can accommodate and you have to figure out what should back down first but, I realize that there's this hope that there'll be big wholesale storage but in the meantime we're mostly using rotating motors to fill in when the intermittent resources are not there and that means giving them a payment stream that keeps them alive and giving them a signal to be built when they're needed and neither of those were what the markets were initially designed for. Power plants were built to run not built to be there once in a while. Nonetheless I mean this is, I was at Harvard Electricity Policy group last week and we were talking a lot about running base load combined cycle gas plants that were built to be base loaded and how you cycle them and how you move them up and down and somebody said, "You know this isn't new, we changed the function of resources a lot of times in the past, this is just the latest example of something that's happened a lot of times before,

Its just kind of mind blowing to think about it with this set of resources because we think about it as new, but the thought if you take a resource and run it in a different way," yeah that's, assuming our commitment to using the resources we can't turn off the same way continues and is real, then we're going to have to figure out how to pay the ones we can turn on and off.

MR. MOUNT: Tim Mount, Cornell. I have a question relating to the wholesale retail issue that you've already touched on. Has there been any development in the role for aggregators as a way of changing residential customers into a wholesale custom?

COMMISSIONER LAFLEUR: Well it certainly has happened in the demand response world where if you look at demand response which we pay as wholesale resource, it can be one big steel plant like Alcoa, I guess that's an aluminum plant but whatever, some big plant that interrupts a shift and gives you a whole bunch of load when you need or it can be a whole bunch of customers with pool

pumps and water heaters that to PJM just looks EnerNOC or Viridity or Comverge and they don't talk to Mrs. O'Malley with her water heater. And so those aggregators look like, well they're by their very word aggregated so they look like a resource.

When I walked out of distributed energy resources, I think as frequently happens, California has stepped into the lead and said we'll figure this out and figure out how you take a lot of things behind the meter and aggregate them. I think this has to happen because I just don't see, if I take off my FERC Commissioner hat and pretend that I was just a person who had a house or something, I for sure don't want to have a contract with Gordon. I couldn't be bothered, I don't even want to look at my electric bill I want Bank of America to take it once a month and if they just tell, let me know if I run out of money in the account. So I for sure, I'm not one of the ones who wants to be on my phone figuring out when to turn things on and off so I need that

aggregator and I think there's more people like me than not like me who need the in between in order to get that. I don't have a pool, but if I had a pool I know I wouldn't fool around with a pump, I'd want somebody else to do it so I think there's a real role there, and when there's a role and people believe there's a revenue stream and they believe it's going to be there for a while they'll start to do it.

MS. BROWN: Hi, Marilyn, I'm Merwin Brown's cousin. I want to continue the conversation about behind the meter demand side resources. Harking back to your notion that the states and federal governments are getting involved in that market and they're mandating and they're interfering and, and logically because energy efficiency has a lot barriers to it. It won't happen naturally very easily there are aggregation options but still there's a big mass of potential there. You mention that in the Clean Power Plan, the coexistence of these things is a little bit tenuous and I don't think that the

Clean Power Plan is going to stimulate much energy efficiency by state. I don't see our regulators saying, "Well I'm going to go to my state energy office and I'm going to get them to promise to deliver a lot of efficiency," so, but I know that's your purview really but you are responsible for (inaudible) transmission side, going back to Heather's comment, she really likes that, it's so much easier.

Well, I had the opportunity to participate in some FERC Order 1000 transmission meetings and you know those --

COMMISSIONER LAFLEUR: God bless you, thank you.

MS. BROWN: I know, I know. Those no wires options are not getting much play in the South-East and they are forecasting significant load growth and you know proposals to build this and that, here and there. I'm just not seeing efficiency or even you noted 1.1 percent deduct-reduction in load growth in 2015 over 2014 and that's a number I hadn't seen before --

MS. BROWN: I'm seeing such an over commitment I think to new builds of transmission, so what's going on there?

COMMISSIONER LAFLEUR: Well, the number you site, just for everyone's benefit, the folks who put together this State of the Market, on a national level we are seeing low growth, really staled to a little bit negative. Before I get to the part of energy efficiency you're talking about since it is a DOE meeting there is a big hunk of energy efficiency that's passive that even I'm dumb enough to do which is Standards because I don't even have to think about it. If I need a refrigerator, it will automatically be efficient because Pat required or people who work for the DOE put out standards and made it efficient and a lot of that is, the standards and the codes are increasingly-- I was one of the first people in Massachusetts to buy a super efficient refrigerator in 1992. I had to drive out of my service territory because it was one of the first pilot ones and I don't remember how much it cost

except that my husband was really angry at how much it cost. He called it a superexpenso. But now I could go blindfolded into a Home Depot and any refrigerator would be so much more efficient than that one I bought and so that is depressing or stabilizing the load.

I think that the requirement in transmission planning of Non-Transmissional Alternatives is well motivated. In and of itself if there is nobody there to sponsor the Non-Transmissional Alternatives I'm not sure that's a robust enough thing as just as a transmission planning requirement given the complexity of the stakeholder discussions to make it happen. Where we've seen efficiency really blossom has been where the state's embraced it. And this is something, you really asked a bad question because I used to do this back 15 or more years ago, no God, 1992? How many years ago is that 23 years ago? Anyway, a long many years ago when they started doing efficiency in Massachusetts and Rhode Island there were no

vendors to do it. But again when you make a payment system and say we're going to pay for this you build an infrastructure and once the infrastructure comes it will start delivering the services that's very irregularly sprinkled in different parts of the country, parts of the country that have had stable rates and not as much of a big environmental movement have not really spawned that. I think you need those aggregators or vendors or organizations pushing it order to be at the table and saying, "Hey, we can do targeted efficiency here instead of building this substation or whatever". It's not just going to come out of a transmission organization. We're seeing this spread to more parts of the country.

CHAIRMAN COWART: Thank you. I saw Chris had a card did you-- okay, great. (laughter) You got us all going Commissioner.

One of the things, I want to take you back up to the larger scale again for a minute, one of the things is that most of the studies that have been done about Renewable Integration shows

the bigger the footprint the easier the job. You have to opportunity to match resources from around a big area. Wind is blowing in one place when it's not blowing in another. There have been a number of proposals to link the asynchronous interconnections. I'm just wondering if that's on the docket or on the horizon for consideration. It does seems like there could be in certain places some real big benefit in doing that, matching resources, especially renewable energy resources with others.

COMMISSIONER LAFLEUR: That's a great question.

A few weeks ago I was in Houston and visited with Clean Line and saw their map of the United States and all the D.C. that's proposed. What we're finding is that the, first of all the Interregional Coordination Requirements of Order 1000, if we're being honest, have not spawned a renaissance of interregional big projects. I think there is a lot of reasons for that. One, is the stale low growth, the other is there are a lot of regional projects but the requirements of Order

1000 on inter-regional work, almost more a kin to what 890 was like on regional, just kind of coordinate, talk about it and it requires quite a lot of regions both deciding it's in their interest and not too much of that has happened yet. It's something we potentially look at the Technical Conference, we'll certainly look at going forward in terms of is there more that has to be done at a policy level.

The other big problem is that even if the, like some of the Clean Line, for example, proposals have whatever they needed FERC. They have a ray making structure, the have an incentive structure they have a proposal and so forth but the siding is still done at the state level and it just takes one state to say "No" in order to stop on of these big projects and I personally don't see a lot of prospect for Congressional action to create more federal siding. It just seems to be the opposite of the way the body politic is moving. But I think state-- certain types of resources are easier to show benefits (inaudible)

along the other than other types of resources and so there might be big benefits for the country if you built a line from the Midwest wind quarter to a population center but if you have to get every town and city and state you cross to believe that, that's been a little bit of a barrier. You probably are close to this. I'm interested in your thoughts.

CHAIRMAN COWART: Yeah, well one of the things I just wanted to mention, you mentioned the anniversary of the Energy Policy Action I think it's now the 11th.

COMMISSIONER LAFLEUR: That's right, this summer.

CHAIRMAN COWART: It did give states the ability to form multi-state compacts for the purposes of siting renewable work, uh, multi-state transmission. They don't have to go back to Congress to get that, they already have it. But nobody, I mean nobody has done it. You do find states exercising their sovereign jurisdiction in ways to frustrate generation mixes they don't like. So, it's a lot of, I think, part of our

dysfunctional national politics is spilled in to the energy realm in ways that are really unhelpful. I don't know what we do about that. It's affecting every part of our public life.

COMMISSIONER LAFLEUR: Energy it tied into economic development and so states that have an up side to big wind projects and all are more interested in big transmission lines than states that might be the custom and closing down things that are local and have jobs. When I talked about Congress I didn't mean that piece of the law but there is another piece of the law that the DOE would decide quarters that were congested and people would come to FERC and we would site lines and there have been a 9th Circuit case and a 4th Circuit case that largely kind of stopped that from happening absent for the Congressional action that, at least right now, is not imminent.

I think there has to be-- if people really all agreed that climate change was something we all agreed on and we were going to get there and there was a consensus and we were

going to get there then there might be more of one state coming with the next state. As you well know that's not the consensus view of everyone in the United States who are of all the states governments and so even that basic that I think-- a state has to be motivated to help pay for or help site a big line to bring renewables from another state and they're probably going to do it if there is a reason for them and if they believed that there was this huge environmental need to do it, that's a reason. If there were jobs in the state, that's a reason. If they were going to save money on rates, that's a reason. But if they don't believe one of those reasons we don't have a hammer, there's not a federal requirement to do it, as you know.

(laughter)

SPEAKER: It was a very broad set of topics that you touched on. We greatly appreciate your being here with us. Unfortunately, we can't continue this conversation for the next hour.

COMMISSIONER LAFLEUR: Well, I'll come another

time. It's funny when I talk to people about, who don't know anything about energy which is most people, and describe what FERC does they kind of look at me like, well what do you do after 10 o'clock? (laughter) Because it sounds so narrow, Well do you do the nuclear power plants? No, we don't do that. Do you do my electric bill? No, we don't do that. But then when you're actually in that little world that seems so broad, it's all prospective, you know.

CHAIRMAN COWART: Well, we're really honored to have you with us. Thanks for coming. And I think we should return to the panel and have the opportunity to really get into that.

(Discussion off the record)

CHAIRMAN COWART: All right, Paul.

MR. CENTOLELLA: Thank you Commissioner. We're going to go from big federal level back down to distributed energy resources and talk some more about the different visions that you heard before our Commissioner on the floor was here. So let's open it up to questions and I see Pat has her card

up so maybe we can start there.

MS. HOFFMAN: So I found it a very fascinating discussion in looking at the core building blocks going back to-- a lot of the speakers talked about granular load forecasting, true cost of service.

The question I actually have is probably more for the state people in the audience and the panel, your thoughts on it because at the end of the day it looks like we're going to have to really rethink what is fair and adjustable rates and equity among consumers if we're really going to have to get into that microanalysis of the true cost of delivered. You know, the electricity delivered.

MR. CENTOLELLA: So, I can offer an opinion but this is from a former state regulator and I'm sure other state regulators also have opinions.

So, I always stated out from the question of fair and equitable starts with what is the economically efficient answer and then one justifies variations from that but of course many

people start from the prospective what has the past been and say can we choose the past, which sometimes you can but many times you can't. So, that tends to produce very different perspectives on the atmosphere in the eyes of different people. That was a summary I think of our lunch discussion. So, were you going to comment on that Rich as the former regulator?

MR. COWART: No, I have a question for later but maybe we can start here and work around.

MR. CENTOLELLA: Sonny.

MR. POPOWSKY: Thanks Paul. It's just a terrific panel. I just had a basic question about rooftop solar. Every time I open the computer I get a pop up add from Solar City, I can save 50 percent on my bill, they don't know what my system constraints are, they don't know where I live and whether or not I get a solar panel has more to do with my credit rating than my distributed locational marginal cost.

So, even if you have all this information as utility, maybe Heather you could

answer, you don't control who, or how do you plan for a product that's sold by pop up adds not by system planning. So what do you do with this information in order to make-- to get the results that you want in this kind of market.

MS. SANDERS: So, it's why forecasting is so important. It's so we take into account that solar that comes on and what you're talking about here is how much do you do in planning and how much do you take care of in interconnection. So right now we would plan this system based on load forecast that are historical. We may or may not know that there is solar there because the net load will just change. It will just show up as load so what we're working on is that more granular forecast. So we cast the load piece and then we forecast the solar PV contribution. So we know what that is so when we plan the system we recognize that and upgrade for that.

But what's happening now is that, we don't have that information as easily as we can and we can't project necessarily where things are

going to be so we just do the best we can in planning and this is one of the things we talk about in the DRP is getting better at forecasting. We want to include these things in the forecast so we don't over build or miss some critical info-structure that we need in order to operate the system, like I said about the troublemen. Now we take care of a lot of it in interconnection. We've established what's called our Rule 21, some parameters so people with rooftop solar can interconnect and it doesn't affect the grid and then that gets reflected in our load forecast because they're historical and then we wouldn't build for that load we would build for that net load. Does that help? Sort of?

MR. POPOWSKY: Yeah sure. And then I guess the pricing comes in that too because even in California you continue with net metering as your pricing and clearly that's not going to give the kind of price signals that you're talking about.

MS. SANDERS: Yeah, the whole discussion of price signals is a whole other one. Yeah, net metering the biggest challenge there is the cost shift. I don't know, maybe someone else wants to talk about the price signals.

MR. KALLOCK: I'll chime in here but I'm not an expert in this area, it's really a policy area but if you remember the slide I had up there where we were optimizing on TRC, the TRC test was.94, it was close to 1, but the utility cost test was 4 so the utility had extra money that it could essentially put toward incentives. But then you have a regulatory or policy issue of how do you handle those incentives? You don't want to incentivize solar to one customer and not another customer or give one customer another one.

So what we've kind of thought about internally, and again I'm just speaking from our opinion, was the utilities could offer bounty to the solar cities of the world to target this neighborhood versus that neighborhood. It goes to the third party developer, it doesn't go to the

customer. But that way you get the solar put in there the way you want. Just an idea.

PROFESSOR CARAMANIS: May I respond? The issues of how do you get in the incentives, the local, sort of time specific incentives, you can't get them in if your pricing on an average cost basis. On the other hand here is-- so we did the distributed control or the distributed sort of marginal cost base incentives or prices if you wish, can bring about important benefits not only for those who participate in them but also for the rest of the people who do nothing essentially.

So, the key here, particularly on the first question of how do you get from today's average cost pricing and fairness, the notion of fairness, how do you depart from this notion of fairness that requires that you treat everybody the same to some sort of a pricing scheme or incentive scheme that doesn't treat anyone the same without objections though.

So the first thing is to decide on providing the opportunity to distribute the energy

resources to choose between seeing this sort of average and fair in some sense or equitable price or to see the actual margin cost base price. And it's possible to have sort of a newer situation like this in which you price some people on the bases of average cost and others on the bases of larger cost. So that's one.

The other thing is, is it fair to give the same incentives, for example net meter, right? Net metering is wonderful if it's based on an (inaudible), right? And if (inaudible) is everybody seeing the (inaudible) in location specific marginal cost.

But net metering on the basis of three months or one month and the average cost is not necessarily correct. So the idea is, is it fair to give the same subsidy to resources that bring about different value and different savings to the system in terms of avoided cost or info- structure in terms of avoided costs or variable costs, fewer costs, CO2 costs and so forth. That's a different notion of fairness. Are we locked into-- so

that's a political discussion. It's a valued discussion. But we don't, you know-- people say we should have the same tax rate to everyone, regardless of income. So that's, that's a philosophical approach to what fairness is.

CHAIRMAN COWART: On this point as a former regulator I will chime in and just observe that we have historically charged everyone the same price regardless of the fact that they historically impose different costs on the system for reasons of social value.

I'm personally in line with your observation that we can continue to do that for a lot of different rate categories at the same time that we offer differential benefits to people who optionally depart from that rate design in order to do something different as a DER custom which is the place we're in right now.

But I was going to ask the question of the panel and to us all really, how far do we want to go with time sensitive, locational sensitive variable LMP at the distribution level anyway?

There is just this question of purity of the pricing structure versus the reality of what people actually want to do and how much you have to put on the table to get the resources you actually need to accomplish the basic goals of the system. So, I'm convinced that there is some nice middle ground here that we will get comfortable with without having the price structure reflect the high degree of variability that was in all of your charts.

PROFESSOR CARAMANIS: Well, absolutely. Price variability if you have organic or marginal cost base pricing to which participants can respond. The overall price or the overall cost variable because it goes down, it does go down. So then, how far? As far as it makes sense and as far as it is acceptable, you know socially acceptable? As far as society is willing to go along with it? But having the facts and the measurements and the costs and the benefits evaluated is important.

SPEAKER: And I'd also say that allowing a high degree of variability at wholesale is a

different thing altogether.

CHAIRMAN COWART: Let's move on recognizing we only have twenty-five minutes and we have a bunch of cards up so Carl do you want to do something with--

MR. ZICHELLA: Yes, I'll be as quick as I can. Well, thank you for a great panel. It's been extremely interesting to see the level of work that has gone on into trying to understand how we would do this. It's very, very impressive. One of the things I wanted to mention is the conversation with distributer generations is almost exclusively been about what it cost the system and then cost shifting and all this. So, I think if we're going to get people who are investing thousands of dollars of their own money in technology that does have a boarder system benefit, having this kind of conversation, come to conclusion about what that sharing ought to be is really the way to go. I'll point out that's one of the recommendations that we made in our Modernizing the Grid Report in the year before

last. So, I'm really gratified to see this come forward this way. I think it's necessary if we're going to get past these conversation about etching net metering programs in stone. We're going to make changes, people have bought into them, we really need to make them fair to both sides because we are seeing great benefits as you're shown.

One of the things I wanted to mention though went to understanding the distribution system and this may be, Bill, goes to you a little bit is the great detail you described in analyzing how the system looks down to feeders, circuits, transformers. I mean that to me is really impressive but one of the things I've learning in recent months is you can't always depend upon what you think you've got there because after every event that a troubled guy that Heather has gone out with goes out and makes a change to the system. It may not always be perfectly recorded. You may wind up with some of the customers on a phase that you didn't expect, that kind of thing.

So, there needs to be an understanding a better tracking of the changes that are routinely made to the system and the distribution grid, just fixing stuff that happens that Heather was describing to us. And by the way Heather I've only read the executive summary, I'm sorry, not five hundred pages. I'll get to it but I need to go on vacation in order to get to that [laughter]. Thanks for your work on this.

PROFESSOR DIVAN: I think it is a very important question, one that we've struggled with because we've done the same level of modeling in all the distribution feeders right down to transformer level and even down to the meter level. The models that utilities have are very inaccurate to say the least, most of the time, and it's very complex in any case because you have to take into account the variability of the load and everything else which is kind of a high level of complexity to add on it.

What we really discovered is that when you actually start controlling from the age of the

grid you saw some of the data that we showed, there is a cell balancing property that emerges where the entire grid kind of becomes well behaved and very predictable and all the dynamics that are still there and kind of get smoothed out completely. In that case, when you think about optimization and both of the control our utilities do they're very complex and Heather talked about configuration and the networks changing all the time and when it changes you really kind of do VVL because it's very much configuration dependent.

Where we've been able to demonstrate that when you take that and you have a cell balancing property and make the system completely independent of the configuration. So we don't need to know the configuration we don't need to know individual loads we don't need to know. But what we are doing is compensating at each load or at a fair number of loads dynamically compensating to smooth everything out and when you do that's all you need and you because less sensitive to this detail if you want. So you want to detail to

maintain service at an individual load but you don't need that to get the control of the system that we're talking about.

MS. SANDERS: You make it sound so easy.

PROFESSOR DIVAN: It is.

MS. SANDERS: It's not. What we also really need to be able to do is, when we calculate this integrated capacity availability we do it based on the normal topology and I was texting again, we do some twenty thousand switching operations every year. So what we really need to be able to do is not just study that in its normal configuration but in the other configurations as well so we can maximize the amount of that DER that's deliverable at any point and time. And we don't have that capability now and that does require these complex modeling. Now all of this stuff about getting it to the edge and I don't know how that works, so more to learn.

CHAIRMAN COWART: Carl, just following up on the question, the process that we go through now as Jennifer was saying, we're kind of using

the system as expected and we're doing an annual forecast. That's the first blush. But then within that we have multiple portfolios that we call switching. So we can say that X amount of switching takes place, I can't remember the number that Jennifer just said, thousands, [off mic talk] Heather, sorry, thousands of switching but we can put those into portfolios and we can say, okay, given this amount of switching here is what the DER would look like. Here is what the optimal forecast would look like.

So that goes into sort of the stochastic forecasting that we're doing. But then, as we get more and more into this analysis and the data become available quicker our forecasting will go from, on an annual basis to a monthly basis to a weekly basis. Then we'll be able to adjust for things going on in the grid. So it's just a matter of processing and time.

MS. SANDERS: I just thought of this, if we have more monitoring sensing out there we'll be able to drive the configuration as well. So what

they change or what they forget to switch back will become less important because we're going to need that situational awareness anyway. I don't know why I didn't think of that first.

MR. CENTOLELLA: A quick footnote from our lunch discussion, DOE has funded some work on transmission topology optimization which very interesting in terms of increasing transmission capabilities. Wanda.

MS. REDER: Well, I had two and the first one was one the work force implications. So the regular planning takes a bunch of work and to get it down to the (inaudible) is huge and even if we depend on sensing and increased automation the journey is going to be interesting and I think we need to have a very honest conversation about the skill sets it takes to go from here to there.

So, that was one but the other one is, on the distribution side we expect accountability, reliability and safety. And yet there is acknowledgment that there is more and more back feed on to the system and fortunately we are

starting to get out hands around that from tools and such but it seems we have the distribution utilities in a bit of a catch twenty-two right now on the operation side. I just want to kind of open that conversation and so, okay so how are we managing through this reliability, safety aspect as the system is changing and what can we do to make sure for society overall the journey is the right one.

MS. SANDERS: Yeah, we have a whole team working on that because it is essential and it really is important and I don't even know the answer to that either but we do have a whole team on that. It's front of mind especially as we go on these ride-alongs and we see what these guys are faced with every day, it's really important. They have those maps in their cars and they talk about, or their trucks, and they talk about how they are being upgraded and how they work and how they don't work so we need to make that connection and-- we have a whole team on it so it's really important, I couldn't agree more. What we do is

we really try to involve operations in these discussions about interconnection and protection schemes and how we're changing things up.

The particular trouble man I talked with is also a trainer of others and what he noticed is, I have to retrain these people four, five and six times and they don't change. So it's really important, it's really challenging, mistakes get made because they don't know to think about it differently.

There was another one there was zero current on the line, breakers open, right? Guess what breaker is not open, they paired up a whole bunch of solars same day. And so their troubleshooting actually dropped load because they isolated that circuit because they thought the breaker was open. And I'm like, oh my gosh. These are the examples of things from an operation perspective we get and we need to train and retrain our operators but there is so much to know and so I'm with you hundred percent on that one. We have a workforce team that's part of our grid

modernization that's working with our customer side and our operations, our trouble men out in all the districts and so it's a tough one, it's a very tough one.

PROFESSOR CARAMANIS: If I may add there is a huge difference between investment at the utility level, the distribution utility level and the types of investments that DPAC was talking about for example which are very small and numerous and distributed and could potentially be undertaken not by the utility but by the electricity users, the participants in to the grid because they are small investments they are sort of this create and small decisions and they risk associated with them and the matching of the cost of the benefit can be done automatically and innovation can be fostered and so on the base of design on the base of manufacturing. How many of those do we manufacture? What new devices are being manufactured? If these are rewarded on the basis of their actual benefits, the local marginal benefits and then the long term forecasts are very

important when some of the things of investing into a new generator. That's exactly what they do, they try to forecast the LMP's for ten, fifteen years and they are different scenarios and so forth.

So let the individuals who invest in these small investments through their load aggregators, through sort of regional neighborhood coordinating agents if there are any but I think you can do it by yourself. You don't need to run around and turn on and off things. You need an application on your smart phone and that's it. Where you can specify some broad preferences and it just works out at the distributor level. Now that communication is cheap, now that computation is cheap if we get our act together we can do it. And then utilities right now, okay some calculations are better than others but many don't know what the capabilities of the transformers are, what the lines do and so forth. Do they have an incentive to find out? They could if we were doing distributor control, if each line could

calculate its losses and convey that to people who are, whatever, distributor energy resources that are connected to either side and so on. Then, there would be the motivation so find out about these costs and distribute the energy resources, that's the idea. They constitute investments and decisions that can be taken up by individuals who can also undertake the risk in some sense either by themselves or on a neighborhood or sort of a grid basis and so on.

These are, I think, the transformation, the paradigm shifts in investments before and investments after the distributed energy resources. We used to may our light bill, that's why fairness was very important. We still say we pay the light bill but it's not the lights we're paying for. Very different type of services that we're getting.

CHAIRMAN COWART: Let's try and get a few more people in. Merwin.

MR. BROWN: Thank you, Merwin Brown, CIEE. One brief comment to follow up the

conversation Carl and Heather had where Heather mentioned monitoring, I might pass along some information on the micro-synchrophasor development that we're doing.

What we've learned from about a hundred units being deployed in various distribution systems now is that you can see things such as phase imbalances, you can see where relays are open and you can see what the load is behind a distributed generator with these devices. Whether they are worth it economically yet or not, we're still in research. But they are beginning to be deployed now in some pre-commercial will applications.

The question that I had was that in Bill's presentation, the work that you guys did was working under, I'll call it the assumption, that there would be no reverse power flow in a line, as I understood it. And you came up with the value of distributed generation of that scenario. I think there's going to be a lot of pressure to go ahead and force reverse power flow.

Eventually the Southern California, Los Angeles basin is going to want to move out on a very bright sunny day power into the rest of California or into Nevada or Arizona. So is there any thought on what would be the increased value if any and what it might-- any comments on what it would take let's say in maybe physical changes in the grid to be able to allow and capitalize on reverse power flow?

MS. SANDERS: So reverse power flow in our system has not been a problem. We have a lot of reverse power flow, I know, don't say that out loud. But it hasn't been a problem and it's not a problem because of the way our system is designed. What you get before you get a problem with reverse power flow is you get a limiting factor on voltage or thermal loading. So reverse power flow has not been seen as a problem on our system yet.

What we're doing is as part of one of our demo projects in our distribution research plan, we are going to study the reverse power flows impact on the substation because all of the

cities to date have just been circuit to circuit and so the limits will bind there. What we're really concerned about is the reverse power flow because you have multiple circuits going into one substation will overload the transformer in the substation because regardless of which direction it's going that transformer has a loading. So that's where we're going to get into trouble in reverse power flow I think from there. So we're working on demoing that capability and what it is. But for now, on our system we haven't seen problems with reverse power flow, including the protection or the voltage. We get a different binding constraint first.

MR.KALLOCK: That's absolutely correct Heather and that's exactly what we've been finding. Our modeling and our optimization algorithms allow us to switch on the assumption of no power, no reverse power flow or reverse power flow. So the example I was showing you was simplistic. We had reverse power flow check the-- to prevent that is the strength to the

optimization so that I could show you that it was 7.38 megawatts on that one chart. If I had taken that off of course it wouldn't have been so clean and easy to demonstrate. But, absolutely great question. Reverse power flow is not an overall constraint as were finding as well.

PROFESSOR DIVAN: We've done extensive simulations and we've now got a few feeders where we're running with high solar and we don't see that diverse power flow is a problem and we've also seen that if you manage the voltage properly which we are able to do then there really is no limit as to how much you can do until you hit some fundamental constraint in terms of the generation and putting fuel back into the tanks.

CHAIRMAN COWART: I'm sorry-- if it's quick?

SPEAKER: I hope it's quick because I'd like to ask another following question--

CHAIRMAN COWART: Well maybe we should move on because we have--

SPEAKER: The only other question is

would networking the distribution center make it even better for reverse power flow?

PROFESSOR DIVAN: We've got solutions that allow you to control the network system a little bit better but I mean under traditional controls, I don't think so, I think it's a problem.

CHAIRMAN COWART: Anne.

MS. PRAMAGGIORE: Thank you. Anne Pramaggiore from ComEd. Great panel, I've really appreciated the input. So my observation from your collective presentations is that while typically, or often in transformations we see technology sort of over runs policy or regulation. In this case it seems to me that we're got policy in one sector of our business that's really outrunning the technological ability of another sector, which is the grid. So the technological features of the grid and our ability to actually economically capture what we're trying to do here is pretty darn limited. And so my question to you is somebody who’s got to actually operationalize all we're talking about here, do you have an

opinions on what might be critical path on the road map to get from here to there; what you would tackle first, what you would consider the most critical elements?

MS. SANDERS: So for us I think the most critical thing is just getting the monitoring out there so we know what's going on and then getting our field personal trained to know what questions to ask when they see things that would normally lead them to a certain conclusion. So like no current on the line doesn't necessarily mean your breaker is open. So that would be the number one priority is to get that visibility.

The second piece is the analysis. What does it mean? And then the third piece is the control. So what we're looking at right now is as these DER's come on the system can we and we are doing this, we're adding a lot more automated switching and fault indicators so that we can sectionalize better, we can maximize the use of those DER's and minimize the number of customers out.

So as we go through our vision of grid modernization, the monitoring, the analysis, the control piece and then eventually the reliability optimization and then farther in the future, depending, the economic optimization. So you go through these paths of certain software and info-structure that enable these capabilities for the different uses.

The other piece of this is this grid reinforcement piece. You can't expect us to be able to use DER's and operationalize them without these things. You need switches. The IT and the OT has to come together. So priority wise it's really getting the information-- first getting the data, being able to analyze it and I know Merwin and I have talked about this quite a lot: What's going on that you don't know that's causing you problems that you don't know about? So that's what we're trying to think from a priority. But we don't get to decide, the Commission decides for us. So we're really trying to help line up, you know, this is what you're trying to do and this is

what it takes to do this and there is a lot of competing discussion about that which is why, you know I suggest again getting this discussion going about these equivalent solutions. If I don't build infrastructure and I put DERs in to fulfill that function what else do I need to make sure that get operationalized. So, just to have that understanding and that discussion.

CHAIRMAN COWART: Okay, Tim.

MR. MOUNT: Tim Mount, Cornell. The panel did a very good job of identifying all the challenges we face on distribution systems but really Professor Divan is the one who provided a solution to, you know, one of the problems that's got to be solved and I would characterize it as: Solve local problems locally. If you add distributed storage to this model then you can manage your daily load profile keep a power factor with in a range.

My question to Professor Divan is who should be in charge of doing this in the sense of do we need to have a distribution system

operator who decides what needs to be done and if that's the case should that person work for the ISO, for the utility or be an independent entity and I would like to add just a little corollary that Cornell does it now. We have thirty megawatt load, we manage our load very well and we maintain a stable power factor. Goodness knows how the utility guys do it but we get punished if we fall outside it very simple market mechanism.

PROFESSOR DIVAN: We've now got about twenty-five or thirty utilities that are using this on many feeders so we've now got a lot of data that has is beginning to show us that it is possible to stabilize the voltage across even long feeders, of course shorter feeders and is able to kind of compensate it out and once you do you have the ability to kind of move the voltage up and down and do active demand control which is from the grid side as opposed to the customer side. So you can do that without impacting equality of service. And I think they've been able to demonstrate that over and over again so now, this

is all good.

The next question you raised I think is an important one. I mean in our mind what we've done so far is really treated the utility as our customer and giving the distribution utility the tools to kind of begin to do things with their system that they have not been able to do before. So whether it's demand management-- so, a lot of the co-ops have been able to use this for big demand control because it's one of their biggest costs so they, you know, so when their big demands charge hitting they can ramp down the voltage and save on the energy costs and that's net saving for them.

So far we've only been working with utilities but is it possible for some distribution utilities who kind of coordinate and give it to somebody else and then charge for transmission support? We're already beginning to see that we have people like Southern Company that are starting to use this to try and see whether they can at couple substation level, you know, get

significant jump of power that they can use to control its support desk for transmission. So we're beginning to see all these things actually emerge from data on the field right now. I'm not sure I fully answered the question but there were a lot of elements to your question and I can answer you afterwards.

MS. SANDERS: Do you want to know what I think?

PROFESSOR DIVAN: Yes, please.

MS. SANDERS: You know at Edison we see the DSO's a real natural extension of what the utility does. You know when you think about what a DSO needs to do, it needs to plan the system and operate the system and make sure that it stays reliable and safe, so while we do planning today we need to evolve that planning. While we do operating today we need to evolve that operation and then the new function is to lay our market on top of that from a retail perspective. Now we have a lot of those mechanisms already.

So from our perspective we have a lot of

thinking about this. There are absolutely implications on the business model to doing something like this and to be an independent selector of solutions and so we're just starting this conversation right now with in Edison so I've only gotten to the point where we can say we see this as a natural extension of the utility. We're not exactly sure it looks like, so hopefully that's a helpful perspective.

CHAIRMAN COWART: Okay, Jeff.

MR. MORRIS: Thanks, I'll make mine quick so we can get to Mark's better questions. My question is for Heather. Edison does a life cycle risk analysis in your integrated research planning much like our utilities do up in our neck of the woods. How do you propagate our the granularity you have with load for casting and the DER process into that and I guess isn't there much less capital risk in looking at some of those DER investments versus what you're doing in your ARRP plan?

MS. SANDERS: We're working on it. So

we have three different ways of looking at this. There is the distribution planning aspect from the load growth and that satisfaction. There is the planning aspect from the infrastructure replacement and that happens. And then from the reliability and the risk, so we have a prism from work that we apply and so we are, well first organizationally we moved the info-structure replacement folks back into distribution engineering. We also established a very direct coordination with the reliability planning as well. So first organizationally to get those processes together because they're becoming more dependent so I'm not able to answer the question because we're working on it but it's-- I just sent a question to my engineers today I said I want to understand better what causes each piece of equipment life to deteriorate because there are these assertions about, oh I can relieve loading or I can make the load factor better and it extends life. Well, that's not true for all equipment. Transformers to some extent but the

number of times you have faults also affects life and so their response to me was: We have to talk to these people in reliability, RECB-- all these acronyms, but in that group get that information. So we're starting to do it, it's in our minds on how we bring all of that together. It's really important.

CHAIRMAN COWART: Mark.

MR. LAUBY: You know when we look forward into the bulk power system and how it's changing over time and we see more and more generations shifting from the bulk system to the distribution system we see a lot of challenges from the operational perspective, balancing obviously being one of the things that you need to worry about, observability, what's out there, how much is out there and yet when I was walking by the TV sets at Walmart, well okay let's say Nordstrom, I'm a classier guy than Walmart, I heard the words

around the grid that was getting old, the decrepit old grid and how you need to buy generators, and they would be generators you put right at your house and run on natural gas, and they will be there for emergencies and what a wonderful life it will be. And overtime of course there will be more of these things that will be installed without like you were saying, it's just being built.

So now how do we get in front of this? So I start thinking to myself what are some of the reliability services that, we talked about frequency response and some of the ride through etcetera we're going to need.

We talked about coordination of controls and we talked about the operating challenges. So one of the thoughts that come to my mind, I'm sure there are some guidelines out there already being put together is from a planner's perspective, how do you plan that system that you're giving to the operator so they can operate it reliably? What are the, in fact, there needs to be any standards or guidelines from an operators perspective what

tools and exact guidelines are they going to need? And when we talk about coordinating the controls, I'm not afraid of coordinating the controls, we've done it over and over again for many, many years but now we're talking about a three phase system, what kind of tools are we going to need to be developing here sooner rather than later. So get some thoughts around those aspects now that you've learned so much in recent implementation of DR.

MS. SANDERS: There is a lot there and you almost answered your own question. So from a planning perspective, the planning entities have different objective functions so transmission planning objective function is supply and demand balance and recovering after contingencies. So it's frequency.

Distribution planning objective isn't at all about supply- demand balance it's about managing voltage and overload, so thermal voltage protection, some other things get thrown in there. So, from a grid planning perspective these things can be done this way, you need a coordinated

assumptions. So in California our energy commission does the load forecasting for the state. The transmission planning uses that, then distribution we do a bottom up plan based on the tribal knowledge of the engineers who hang out in those places about what the loading on the circuits going to be. Those need to be coordinated because if we're planning a transmission system that assumes 12,000 megawatts of distributed generation, that 12,000 megawatts better show up in the utility distribution plan somewhere. So, that's step one for planning.

Now, for grid planning. Then if you moved to resources planning, this is where it gets really exciting. So now we're going back to the future in thinking about integrated resource plans and so what we'll need to in the future is think about the construct for committing and procuring resources for bulk system reliability and what that's for and when it needs to be available versus distribution. So when you think about the values that storage or other DER's could provide

to the system, how many of those can you do simultaneously and how will you coordinate that in opera--- so this is a prioritized control because you have the customers priority: I need to manage my peak demand and my demand charge. You have the distribution grid priority is I need to keep my phase balances everything in voltage and then you have the transmission grid priority of the overall supply-demand balance plus the ability to recover after contingency. So, we are working right now with RIS their adventive of facilitating distributed energy resources to purchase, in their wholesale market ahead of us having the capabilities to monitor, understand, dispatch, etcetera, do any DSL functions with them so that nothing bad happens when a central dispatch comes to a distributed resource. You can solve it in interconnection but that would be really costly, or you handle it operationally. So there was a lot in that question. There is a lot to do there. But you just have to think about the different problems you're trying to solve, different

objective functions and how each of those resources can contribute to those objectives in what period of time. So more granular visibility, more granular control, prioritize control, etcetera. And I don't like to make things sound easy because it's not, so I'll let these guys make it sound easy.

(laughter)

CHAIRMAN COWART: So I don't know if it's easy but you just laid out a whole bunch of these cases for grid architecture I think. Paula, you have the last question.

MS. SANDERS: Can I say something about grid architecture?

CHAIRMAN COWART: Okay.

MS. SANDERS: So, we rolled out our architecture at the DistribuTECH Conference this year, it's out on our website. What we're really thinking about from architecture perspective is this is an uncertain future and in uncertain future you want to invest as little as possible of that could get stranded. So what we've done is

we've tried to really push most of the functionality into software and limit the hardware and so we've published our high level architecture which is really very consistent with Jeff Taft and that work has been as well as a concept of operation. So a lot of-- we hired the dream team of architects to come in that have been very active in these different things to put that out so I just want to just make sure you guys are aware of that and kind of what we're thinking in that aspect.

CHAIRMAN COWART: Paula.

MS. CARMODY: I guess I'm the proverbial person keeping everyone from dinner. Just a quick aside from the comment Pat, the comment that you made, that's what gives me a headache twenty-four hours a day when we're looking at kind of pricing and what we're going to be doing with the rates. That's all I can say. It's there on our plate and Rich, you know, I think eventually we're going to get to the point you're saying we need to have something that's going to be there for mostly

everybody in terms of residential customers but there is going to be some opportunity for more precise pricing for things. But it's going to take us quite a while to get there on the state level.

So, I'm kind of the consumer person here, not the techy person here but kind of all my customers pay for all the stuff that you're talking about. I'm in Maryland, a restructured state. Part of the PJM wholesale market. Also in a state that's been very much-- in terms of the legislation that's been passed, supportive on renewable energy in terms of our PS goals. We passed a community solar pilot program. We've got lots of energy efficiency going on. So you're caught with a conflict between lots of: Do it now or do it yesterday in terms of developers, competitive companies, some of, certainly, customers that really want, we're talking about want stuff done now. More activity from investor owned utilities and co-ops wanting to do what the competitive companies are doing in terms of the

DER space. So, do it now, but on the other hand in terms of the wonderful presentations lots of you were making, you're talking about a very kind of complicated process that requires a lot of modeling and analysis and granularity to try to get to the point of, what is the most cost effective, the most reliable way to do thing kind of on the system whether it is done in terms of the distribution and transmission system or you're talking about kind of the customer kind of doing it.

So all I'm saying is you've put us in a stakeholders in quite a quandary with all of this. So I'm going to go back to-- in terms of the distribution planning. I'm in a restructured state, the companies do planning but we don't have a planning process any longer in the state of Maryland has maintained it.

So I know the companies are doing planning but it's not transparent to stakeholders. We don't know what they're doing really. So the question for any or all of you is that for

somebody like me, what would be kind of a top five list of things that you think I should be asking or wondering whether or not my utilities are doing in terms of distribution system planning in this DER world that you think that they may not be doing and they should be doing so that I can take that list back to my companies?

PROFESSOR CARAMANIS: Let me give you my single point here. The single point that I think it missing is the actual awareness and calculation of what the costs are by location and by time. And then that essentially quantifies the distributor control and the distributor decisions and the distributor investments and so on and allows for a coordinated way to go forward and an efficient way from societies point of view. Everything is cost driven so it benefits, equal to cost, right?

MS. CARMODY: Can I just ask a quick question? Are utilities generally doing this or is this something that you find that they're not doing it and you're suggesting that they do it?

PROFESSOR DIVAN: The cost of service model is

not doing it.

MR. KALLOCK: And I'd add to that utilities should be in terms of planning, really calculating what the technical limits are for DER hosting. The integrated capacity analysis in California, they ought to be really be taking a look at feeder by feeder, circuit by circuit basis, what is the hosting capacity and back flow could be turned off and do the analysis. But that's something they need to consider before they are overwhelmed with different resources.

PROFESSOR DIVAN: We work with a lot of utilities now and most of the time you haven't seen that they have the data to really be able to do the analysis to understand what happens when distributed resources are put on the system. We've tried to help them and we've tried to work with them fairly closely. But I think the way we structure the solution that we've been talking about is really to try to get some of the guess work out of it. I think if you can understand what your feeder looks like in terms of current

operation and if you have an idea of how much the projected DR load is going to be to host the capacity then you can at least from the most dominate limit we can all agree has been voltage and distribution feeders. I think our approach has been that you can solve that problem as almost an incremental way. So at the level of penetration you have now you can come up with the deployment level of the distributor solution and as the penetration level increases you can keep going back and adding to those places where the voltages are now starting to become a little unruly and you can-- so that's the fast forward as to how you can at least get to higher levels of penetration. That's how we've kind of been working with high utility (inaudible).

MS. SANDERS: Yeah, I think what's critical is to be really clear about what you're trying to do. So what are your goals? So, the reason I couldn't answer right away is because California has its goals. We are doing this. So our planning process needs to adapt and needs to

be able to handle this. So every utility has it's planning process and where it becomes visible is in the rate cases because that's where you get recovery for distribution upgrades and it's based on load growth. So every utility does planning and that becomes transparent in the rate case because that is where that is, to some extent. So and, slash, return.

The integrated capacity analysis is really helpful in streamlining interconnection. So what are you trying to do with an integrated capacity analysis? Do you want to apply an analysis that gives values that then can speed interconnect? At least that's our objective with that. If your objective is to get more DER's in the system and invest less in the wires then you'll need to have capabilities not of doing planning to get projects, because right now how planning works and its opaque everywhere because it's a utility process so we're working and we talk all the time about here is a planning process, here is what we do, here is why it's

different than transmission, this is how it works. But rather than going in with your forecast assumptions which then will bind based on your voltage or thermal protection limits and say-- then it spits out a project. It says go put in cap bait, go put in the new circuit, go do this. What we need to do is insert the ability to identify attributes that that piece of equipment provides. So for example if you're binding on a thermal you can say well it's really only this way. You need more granular forecasting, you need more granular planning. It’s really only happening in ten days out of the year for three hours. I can't tell you when but those attributes then collectively help guide the DER market for a solution for that, so if that's an objective to get DER's that help defer distribution resources but coming with that though then is the need to be able to see it, monitor it, control it, operate it, maintain it, etcetera. So there is that trade off there.

So it's a tough question and I think the

first step is just the visibility into what are the different steps? How are load forecasting done, you know the low growth forecasting? How is it applied? That is what, what we're really trying to help, you know, our state to understand is how we actually do that. We've never had to before except when we defend the rate case.

MS. CARMODY: And I think the difficulty, and I don't think Maryland is the only state, where you don't have an external transparent planning process. So obviously the utilities are planning. But it doesn't come up in the six-month rate case, we've got very rapid rate cases, yeah. So you're level of detail-- that information doesn't come out so we don't have that kind of planning. We do need to have that planning in order to look at what is best on the distribution transmission system in terms of using those resources to help it run more efficiently. But at the same time we also are dealing with the external resources where the people are coming in saying I need to interconnect and-- with community

solar or rooftop solar with whatever storage will be coming on board and so you've got those issues as well. And I appreciate your-- providing me some things to take back.

PROFESSOR DIVAN: One thing to add to this if I may. Because very few utilities I mean in California and in Hawaii are the only one attacking high levels of solar right now. Everybody else is kind of thinking about solar or in the early stages of it so the way that our discussions have gone most of the time is, you know, what else are we trying to do with voltage control out here. Very frequently it turns out to be demand management or CVR or something like that and you know some of the commissioners are starting to recognize CVR's as essentially being grid side demand management of that.

So you now have a basis to kind of push for things that are really good for society with the assurance that as solar comes in this is not going to be a stranded asset. So with the majority of utilities we kind of use that argument

and I think we've had good luck with that as well.

SPEAKER: It's time.

CHAIRMAN COWART: Yes, it is time. This has been an excellent discussion. I do want to mention that people who still have some appetite for this discussion the Smart Grid Subcommittee was going to meet for breakfast tomorrow at the restaurant at the Weston at seven before we start, so we can have a little bit more reflection there but can you join me in thanking this excellent panel.

(Applause)

SPEAKER: Thank to you all and it's great. An announcement about dinner. Yes.

(Whereupon, the PROCEEDINGS were adjourned.)

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CERTIFICATE OF NOTARY PUBLIC

COMMONWEALTH OF VIRGINIA

I, Carleton J. Anderson, III, notary public in and for the Commonwealth of Virginia, do hereby certify that the forgoing PROCEEDING was duly recorded and thereafter reduced to print under my direction; that the witnesses were sworn to tell the truth under penalty of perjury; that said transcript is a true record of the testimony given by witnesses; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this proceeding was called; and, furthermore, that I am not a relative or employee of any attorney or counsel employed by the parties hereto, nor financially or otherwise interested in the outcome of this action.

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My Commission Expires: November 30, 2016

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