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BEFORE THE
CALIFORNIA ENERGY COMMISSION

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| In the matter of | ) | Docket No.: 12-IEP-1D |
| | ) | |
| Preparation of the | ) | |
| 2012 Integrated Energy | ) | |
| Policy Report | ) | |
| Update (2012 IEPR Update) | ) | Public Workshop |

LEAD COMMISSIONER WORKSHOP
ON
INTERCONNECTION OF RENEWABLE DEVELOPMENT IN CALIFORNIA

CALIFORNIA ENERGY COMMISSION
HEARING ROOM A
1516 NINTH STREET
SACRAMENTO, CALIFORNIA

MONDAY, MAY 14, 2012
9:00 A.M.

Reported by:
Peter Petty

# APPEARANCES

Commissioners Present:

Robert B. Weisenmiller, PhD, Chair and
Lead Commissioner, RD&D
Carla Peterman, Lead Commissioner, 2012 IEPR

Staff Present:

Suzanne Korosec
Roger Johnson
Mark Hesters
Linda Kelly
Rachel MacDonald
Jamie Patterson, Public Interest Energy
Research Program (PIER)

Also Present (* Via WebEx)

At Dais

Michael Florio, Commissioner, CPUC

Other State Government Representatives

Presenters

Lorenzo Kristov, CAISO
Kevin Dudney, CPUC

Panelists

Carl Silsbee, Southern California Edison (SCE)
Jason Yan, Pacific Gas & Electric (PG&E)
Will Speer, San Diego Gas & Electric (SDG&E)
Jaime Asbury, Imperial Irrigation District (IID)
Chifong Thomas, BrightSource Energy
C. Anthony Braun, California Municipal Utilities Assn. (CMUA)
David Miller, Center for Energy Efficiency and Renewable
Technologies (CEERT)
Kristin Burford, Large Solar Association (LSA)
Chris Ellison, Ellison, Schneider & Harris, on behalf of
Pathfinder, LLC/Zephyr, LLC
*Vernon Hunt, US Navy
Rachel Peterson, CPUC
David Berndt, SCE
Valerie Winn, PG&E

APPEARANCES (Contin.)

Panelists

Ken Parks SDG&E
Dave Brown, Sacramento Municipal Utility Association
Hans Isern, Silverado Power
Michael Coddington, National Renewable Energy Laboratory (NREL)
Ron Davis, DNV and Associates
Peter Evans, New Power Technology
Alexandra von Meier, California Institute for Energy and Environment
Craig Lewis, Clean Coalition
Kristen Nicole, EPRI

Public Comment

Pushkar Wagle, PhD, Flynn RCI
Arthur Haubenstock, BrightSource Energy
David Smith, Transwest Express
V. John White

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**Panel 1: Transmission Planning and the Generator Inter-connection Process** (Continued)

Panelists (Continued):



*Questions on working within the new California ISO framework:*

1. *What uncertainties should be considered in the Resource Scenarios?*

2. *How can we improve the renewable calculator model?*

3. *What policies or goals should be considered in the development of the scenarios? How should DG policies be reflected in the scenarios?*

4. *How do we make the process work efficiently so that the identification and permitting of transmission in California facilitates the development of renewable generation?*

5. *Are there incentives or penalties that can be incorporated into the procurement process that would encourage renewable generators to locate in desirable transmission areas?*

6. *What information is needed by the stakeholders (Load Serving Entities, developers, regulators) to assist in decision making?*

LUNCH 12:30 – 1:30

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P R O C E E D I N G S

MAY 14, 2012 9:07 A.M.

MS. KOROSEC: I'm Suzanne Korosec. I manage the Energy Commission's Integrated Energy Policy Report Unit, and welcome to today's workshop on Interconnection of Renewable Development in California.

Just a few housekeeping items before we get started. Restrooms are in the atrium, out the double doors and to your left. We have a snack room on the second floor at the top of the atrium stairs, under the white awning. And if there's an emergency and we need to evacuate the building, please follow the staff outside to the park that's kitty corner to the building and wait there until we're told that it's safe to return.

Today's workshop is being broadcast through our WebEx Conferencing Systems and parties do need to be aware that you are being recorded. We'll make an audio recording available on our website a couple of days after the workshop, and we'll make a written transcript available in about two weeks.

We'll be breaking for lunch a little later than usual today, about 12:30. And, in addition to our panel discussions today, we've also set aside time at the end of the day for more general public comment.

During the public comment period, we'll take comments first from those of you in the room, followed by those participating on the WebEx. And at any time during today's discussions, if you're making comments or asking questions, please come up to the center podium with the microphone so we can make sure that the WebEx people can hear you and that we can capture your comments in the transcript.

It's also helpful if you can give our Transcriber a business card when you come up to speak, or when you're done speaking, so that we can make sure that your name and affiliation are correct in the transcript, as well.

For WebEx participants, you can use either the chat or the raised hand functions to let our Coordinator know that you would like to make a comment or ask a question, and we'll either relay that question or we'll open your line at the appropriate time. For those participating by phone only, not through WebEx, we will open your lines for questions and comments at the end of the public comment period today.

We're also accepting written comments until close of business on May 21st, and the Notice for today's workshop, which is on the table in the foyer, and also our website, explains the process for submitting comments to the IEPR Docket.

So with that, I will turn it over to the dais for opening remarks.

COMMISSIONER PETERMAN: Good morning, everyone. Thank you for joining us bright and early on Monday. Hope you had a good weekend. Welcome to the Energy Commission's Workshop on Interconnection of Renewable Projects in California. This is the third workshop of a series intended to develop a Renewable Strategic Plan for the State.

One of the main outcomes of this workshop will be a list of recommendations for the State, for the Administration and Legislature, and stakeholders to consider as we try to reach, and we aim to reach, our renewable goals, particularly in 2020.

Interconnection continues to remain a challenge that all the agencies are working on together. Progress has been made with activities at the ISO and the Public Utilities Commission, and today's forum is meant to further explore those processes and to think about what next steps are still needed.

I'm happy to be joined here on the dais by Chair Weisenmiller, and by Commissioner Florio of the Public Utilities Commission.

CHAIRMAN WEISENMILLER: Good morning. Thanks for your participation. As Commissioner Peterman said, we're looking at the interconnection issues, both on the transmission side and the distribution side. And certainly we've found challenging issues on both; frankly, we're probably a little bit more further along in resolving some of the transmission issues, although there are tough trade-offs given a very broad range of options we have, trying to figure out what is the best combination there.

So, anyway, looking forward to an interesting day. Commissioner Florio, very glad to have you here today.

COMMISSIONER FLORIO: Thank you, I wouldn't miss it. Of course, we have our own interconnection proceeding ongoing, looking at our Rule 21 for distribution level interconnection. There's been a settlement submitted with broad support that the Commission is currently considering, and I'm looking forward to further broadening my education on these complex, but critical issues. So, happy to be here and looking forward to an informative day.

MS. KOROSEC: All right. I'll just provide some brief background and context for the workshop, go over the agenda quickly, and then talk a little bit about the things that we covered in the last IEPR related to this topic.

Every two years, the Energy Commission prepares an Integrated Energy Policy Report, or IEPR, that assesses energy supply, demand, price, distribution, transmission, and market trends, and provides policy recommendations to the Governor based on those assessments. In 2010, Governor Brown directed the Energy Commission to prepare a plan to expedite permitting the highest priority transmission and generation projects for renewables.

In response to that direction, the 2011 IEPR proceeding focused on identifying challenges to renewable development and discussing efforts, either completed or underway, to address those challenges. This was intended to provide the foundation for a more comprehensive Renewable Strategic Plan to be developed under the 2012 IEPR Update Proceeding.

The *Renewable Power in California: Status and Issues Report*, which was published in late 2011, described the many challenges to renewable development in California and established five high level strategies as the basis for that renewable strategic plan.

Today's workshop is the third of seven workshops that we're holding as part of the 2012 IEPR Update Proceeding, on topics related to those five strategies, the dates of which are shown here.

The discussions and input from the workshops will be used to develop specific near term actions that the state needs to take to begin addressing the challenges that were identified in the Renewable Report.

The third strategy identified in the Report relates to interconnection and integration barriers. And because interconnection and integration are really two separate issues, we're covering them in separate workshops. Today we'll be focused on strategies to minimize interconnection costs and time, at both the transmission and distribution levels. And on June 11th, we'll be covering integration issues.

Our Agenda today, we'll start with presentations from the California Independent System Operator, the California Public Utilities Commission, and the Energy Commission about resource scenarios for the ISO's 2012-2013 Transmission Plan.

That will be followed by our first panel, which will cover transmission planning and the generator interconnection process, including the importance of appropriate resource scenarios in identifying and approving transmission infrastructure in California.

We'll break for lunch around 12:30 and begin the afternoon with the second panel, with updates on distribution interconnection processes based on experiences with these processes over the past few years.

Our final panel will look at modeling and analysis that will inform and support California's interconnection processes, including overviews of projects currently underway and a discussion of R&D activities. We'll then have an opportunity for general public comment at the end of the day, and hope to adjourn by 5:00.

An overview of the information related to today's topics that was presented in *Renewable Power in California: Status and Issues Report*, this report discussed interconnection mainly in the context of challenges to transmission development and to renewable integration at the distribution level in these two chapters.

The report talked about the increasing interests that we're seeing in renewable development in California, and illustrated the extent of that interest, using the amount of renewable capacity in the CAISO's interconnection queue and the number and capacity of interconnection requests in the wholesale distribution access tariff queue.

As of June 2011, there was 57,000 megawatts of renewable capacity in the CAISO queue, and 450 active interconnection requests for about 5,200 megawatts in the

WDAT queue. To update those numbers, as of April of this year, the CAISO queue had about 33,000 megawatts of renewable capacity, and the WDAT queue had around 560 requests for about 4,000 megawatts of renewable capacity.

Interconnection issues at the transmission level that were discussed in the Renewable Report included a description of transmission projects critical to meeting California's renewable goals, the need for a more coordinated transmission planning process, and making better use of the existing transmission system.

This table lists 13 major transmission projects that are needed for interconnection and deliverability of renewable generation to meet California's 33 percent by 2020 mandate. Projects shaded in green are those needed to interconnect and deliver energy from renewable projects receiving American Recovery and Reinvestment Act funding, which the renewable report emphasized as a top priority. At the time the report was published, only about half of these 13 transmission projects were licensed or under construction.

And in addition to these projects, the Renewable Report also identified the need to strengthen California's north-south 500 KV backbone system to address bottlenecks between desert renewable resource areas in Southern California and load centers in Central and Northern California.

One of the main transmission challenges identified in the report is that land use planning and transmission planning aren't well coordinated in California. The current transmission project development process that identifies land use issues and constraints for proposed transmission routes doesn't begin until after the wires planning process is complete, which makes the transmission development process longer and increases the risk that projects approved in the wires planning phase ultimately may not be developed because of environmental issues that come up during the land use and environmental review phase.

Stakeholders in the 2011 IEPR proceeding also expressed concerns that the assumption and processes that are used by transmission planning organizations aren't always transparent or consistent and the large number of transmission planning forums makes it difficult for stakeholders to participate effectively.

Past and current efforts to address planning challenges include the Renewable Energy Transmission Initiative, which was a statewide land use planning process to help identify transmission projects needed to meet the State's renewable energy goals. RETI identified 30 competitive renewable energy zones throughout the state that were most likely for cost-effective and environmentally responsible generation development, with corresponding transmission interconnections and lines. Identifying these areas upfront could streamline the permitting process for renewable generation and transmission projects and reduce time and costs associated with interconnection. RETI also established a precedent for incorporating land use planning into the statewide transmission planning process and led directly to collaborative land use planning that's occurring under the Desert Renewable Energy Conservation Plan.

Energy agencies are also working together to bring the findings from the DRECP into the CAISO's annual transmission planning process and the PUC's long-term procurement process.

Another effort was undertaken by the California Transmission Planning Group, which was formed in 2009 and includes publicly-owned utilities, investor-owned utilities, Southern California Public Power Authority, and the Transmission Agency of Northern California. The group's role is to address California's transmission needs in a coordinated way, by developing a conceptual statewide transmission plan that identifies transmission infrastructure that's needed to meet the state's renewable targets.

The CAISO also has revised its transmission planning process to include transmission upgrades needed to meet California's policy mandates with the 2010-2011 Transmission Plan focusing on the RPS mandate in identifying policy driven transmission projects. Also, to assist generators who needed to meet a construction start date of December 31st, 2010 to receive Federal Stimulus funds, the ISO requested and received a one-time waiver from the Federal Energy Regulatory Commission to exempt upgrades associated with these projects from further study in the 2010-2011 transmission planning process.

Another issue identified in the Renewable Report was the need to make better use of the existing grid, for example, by replacing existing cables with cables that can be operated at higher temperatures, and allow more power to be transferred over the same rights of way; another example is upsizing transmission projects to provide unused capacity that could then be available for future use. Currently, proposed projects are based on need, as demonstrated by individual interconnection requests, but allowing upsizing, for example, by constructing a double circuit line, rather than a single line, in existing right of way would take full advantage of land that's associated with already necessary transmission investment and allow future renewable projects in those areas to be interconnected more quickly and cost-effectively.

Moving on to interconnection at the distribution level. The Renewable Report identified distributed generation and interconnection as a major challenge that affects both project developers and grid operators. This figure from the report shows the large increase in interconnection requests at the distribution level beginning in early 2010 through SCE's Wholesale Distribution Access Tariff, and the report stated that there are similar trends for PG&E and SDG&E, possibly driven by increased interest in programs like the expanded feed-in tariff, the renewable auction mechanism, and utility PV programs. The energy connection process itself may also be driving the size of the queue.

Many of the programs I mentioned require commercial on line dates within 18 months of when contracts are signed, while the interconnection process itself can take up to a year; because developers only have a two-month window that's available once a year to an interconnection study, they may not be able to get the study results, let alone begin construction in time to meet the 18-month on line date. So, in response, developers may be putting multiple speculative projects into the queues.

The Renewable Report also discussed challenges with the Rule 21 interconnection process and discussions in the Rule 21 Work Group, but I won't go into those discussions since we're going to hear more about Rule 21 issues later today as part of Panel 2.

Efforts to address interconnection challenges at the distribution level include the Renewable Distributed Energy Collaborative Working Group established by the PUC, as well as fast track processes available within each of the state's interconnection processes to streamline interconnection solar projects. Also, as part of the Renewable Auction Mechanism Program, the PUC directed utilities to provide maps on their websites that allow DG developers to identify where they can interconnect new solar DG projects on the grid without triggering expensive studies and upgrades to the distribution system.

The Report also noted that new system-side renewable projects will benefit from FERC's approval of combining the small and large generator interconnection procedures into a coordinated generator interconnection procedure for the CAISO. The coordinated process uses a single cluster approach to studying interconnection requests to ensure coordination of interconnection of small and large projects on a transmission line, which can reduce interconnection study times and costs for developers.

The report also discussed the change to the Wholesale Distribution Access Tariff to include a new cluster study process for distribution connected generator approved by FERC for SCE and PG&E. The previous one-at-a-time serial approach required a generator who triggered an upgrade to pay 100 percent of the upgrade cost, regardless of the size of the project, or whether other generators had requested interconnection on the same circuit. Under the new approach, if upgrades are required, costs are allocated pro rata to all generating facilities in the cluster.

And finally, I just want to mention something in the Report that relates both to today's topics and the workshop we held last week on identifying priority geographic locations. Although local governments don't have any authority in the interconnection processes, they can facilitate those processes by working with utilities to identify potential project sites near transmission or distribution infrastructure, which can reduce interconnection costs for a project developer.

So that's a very high level summary of discussions in the Renewable Status and Issues Report that relate to today's topics. The report obviously has much more detail than I was able to cover in the presentation, so I encourage parties to look through the document as we move forward in developing recommendations for future strategies and actions to address interconnection challenges.

So now we'll move into our first segment of the workshop, and I'd like to introduce our first speaker, Lorenzo Kristov, from the California Energy Commission -- I'm sorry, from the California ISO! Lorenzo worked here for a short time.

DR. KRISTOV: Well, good morning, everyone. Good morning, Commissioner Weisenmiller, Commissioner Florio, good to see you, and thanks for the invitation to be here. Let me -- I was asked specifically to talk today about an initiative we've had underway for about a year now, which we initially called Integration of Transmission Planning and Generator Interconnection, the not easily pronounced acronym, TPP-GHP Integration, which in order to minimize confusion over acronyms, we're changing when we file it at FERC because what we really are offering FERC is a revised interconnection process, so it's now called Generator Interconnection and Deliverability Allocation Procedure. And the reason for that is, as I get into this, you'll see that it's because of the extreme importance of deliverability of resources to be able to qualify for resource adequacy capacity that has been driving a lot of transmission needs and has been pointing out the transmission planning and interconnection complications that we have to address.

Let me just make one little comment on the tail end of Suzanne's presentation about addressing distribution interconnection challenges. Many of you may be aware, we have at the ISO an initiative in progress right now on resource adequacy deliverability for Distributed Generation. That's something that was triggered in discussions with CPUC staff about what's going on in the Rule 21 procedure. I have not -- we're taking it to our Board of Governors this week, I have not included it explicitly in this presentation, but I'm happy to talk with you about it some more if some are interested.

So let me get into this initiative. We've been doing a number of things to improve the transmission planning and the interconnection processes over the past few years. Basically, I think, on the recognition that everyone probably is well aware of, that the way the electric industry has been doing things for the last several decades, how they operate the grid, how they interconnect, and how they plan infrastructure, basically every aspect of operation is changed once you start deciding that we're going to change out the supply fleet in a very large volume, in a short period of time, and we're going to go from a fleet that's almost exclusively dispatchable resources to ones where there's a large amount of resources that are not, that are really subject to the availability of the primary energy fuels, and it's just a different ballgame for operating the grid. Add to that the uncertainty about which generation is going to get built where, there's a lot of interconnection requests out there, there's a lot of very healthy competition, but it makes infrastructure planning more complicated when you have an environment of uncertainty.

So, recognizing all these challenges, we've been trying to think, well, how can we modify, improve, modernize both transmission planning and interconnection in order to work better in this environment, in this context? In 2010, we reformed the transmission planning process and, as Suzanne mentioned, created the new category of public policy driven transmission, something which FERC likes very much in that we were ahead of the curve on putting into our tariff, but essentially it says instead of the classical reasons why you build transmission, either for reliability problem, or based on an economic cost benefit, there is now a new reason why we need to identify transmission, and that is we need it to support these changes in the supply fleet that are being driven by a public policy mandate, namely the 33 percent renewable energy mandate.

So, having done that in transmission planning, now we get down to, okay, well, what are the problems in the interconnection process, per se? And how can we bring it into better coordination with transmission planning?

So we identified, really, three primary problems that we're trying to address, and the first one was how can we plan and approve major ratepayer funded upgrades under a single holistic process? We've had transmission planning, interconnection, both of them could drive large costly transmission network upgrades, but they have very limited interaction with each other, they have different criteria for what needs to be built, different criteria for approval of the need for a project, and, on that basis, there was not sufficient coordination between them. And since we're talking about ratepayers funding now a lot of facilities, then we really ought to plan in a holistic manner so that we're taking a step towards doing that, in which less significant sized and costly transmission will be driven through the interconnection process, itself, and the transmission planning process will become the central venue where major transmission is identified.

The second problem that has existed since the ISO first took on interconnection, which was in response to FERC Order 2003, which was that the rules require ratepayers ultimately to pay for all transmission network upgrades that are needed to provide interconnection needs, and that includes not only to create a reliable interconnection and the downstream impacts on reliability from that interconnection point, but also to provide deliverability if the resource wants to qualify to sell resource adequacy capacity.

We had proposed an economic test in our compliance with Order 2003 whereby there would be a dollar limit on how much ratepayers would pay back on the cost of network upgrades. At the time, FERC rejected that without prejudice, they found that what we proposed didn't give them enough detail to decide whether what we proposed was just and reasonable or not, and they invited us to come back and submit a better proposal, and we really just didn't do it. So, at this point, that has been a legacy, that no matter where generators choose to interconnect, we have the obligation under the tariff to provide for their interconnection needs, including deliverability, and ultimately if they proceed to commercial operations, then they get paid back by ratepayers for the total cost.

So now what we've got is, well, 1) costly ratepayer funded upgrades are identified under the transmission planning process, and 2) generating facilities that take advantage of the transmission capacity created under the transmission planning process will be able to have dramatically reduced cost of network upgrades. Generators that choose to locate in other areas of the grid that may be not recognized and developed under transmission planning may have to pay some of their costs without reimbursement; and 3) a complaint that we've heard very often for the last couple of years, given the huge queue sizes, and when we study a queue cluster, we study the needs for transmission upgrades for interconnections, we study an electrical area of the grid at a time, which is where all of the facilities in that area have flow impacts on a common set of facilities, so that they're all really related electrically. And what we've been finding is that you take an area of the grid where you've got a huge volume, say, 10,000 megawatts of generation projects that want to develop, and you plug those into the study and you figure out what network upgrades you need for them, what you get is a lot of network needs and a lot of costs, which are unrealistic in the sense that we really don't expect all 10,000 megawatts of generation to develop in that area. We know what the needs are, we've talked a lot about the net short, we look at the resource portfolios that are being used for transmission planning, and we go, well, 10,000 is really an unrealistic number, and yet the rules say we have to plan for all of the interconnection requests and the costs need to be reflected in the interconnection agreements of projects. That becomes a burden because now the projects are saying, "Oh, I'm responsible for the costs of these upgrades, but how am I going to get a PPA and get project funding?" Because, 1) these upgrades are really costly, and 2) we're not sure they're really going to get built because that 10,000 is going to get narrowed down to something that's probably quite a lot lower. So all three of these things, fixing those main problems, is what's been driving this initiative.

The central design concept, really at a high level -- and by the way, I should tell you I've given you a lot of pages here on the presentation and I'm not going to go through all of them, I'm going to hit the highlights, but, again, I'm happy to answer questions on any of it, but I did give you a little nighttime reading in case you need help falling asleep. The central design concept really builds off of the "public policy-driven" transmission category that we created in the 2010 reforms to transmission planning, and that is you take at a certain time of the year in the planning process, we call it "Phase I," but it's basically the period from January until about March, is when we create our what we call "Unified Planning Assumptions" for the year, we identify what are the public policy-driven objectives that we're going to take into the planning process as planning objectives, we develop a study plan. Parties who are participants are able to put in requests for economic planning studies if they want us to look at particular areas to see if they're economic congestion relief types of projects that would be worthwhile in the sense that they would pass a cost benefit assessment, so we do all of that setting up, essentially, for the study process for the planning in the year. An important piece of that is, given this public policy-driven concept, what are exactly the public policy objectives that we are trying to attain?

And as we started doing this in 2010, well, of course the obvious one was 33 percent renewable energy, but we've got to get more specific about that -- what does that mean exactly? Well, the renewable energy requirement is really over 8,760 hours of the year on an annual basis, the electricity that's delivered to end-use consumers comes 33 percent from renewable resources. And that concept is total volume of energy over a year. But that in itself, we're finding, and here's where the resource adequacy link comes in, just the renewable energy may not drive all of the transmission that's needed for sufficient renewable resources to be commercially viable, that is, to get Power Purchase Agreements, to get project financing, and then ultimately get to the point where you've got the generation on line and in service that is achieving that 33 percent. And the crux was deliverability, that as the load serving entities formed -- negotiated bilateral contracts with renewable energy providers to plan to meet their 33 percent, because they're also under resource adequacy obligations, they have to have a certain amount of resource adequacy capacity every year, they wanted the renewable energy contracts to also be able to count for resource adequacy which meant that those facilities not only had to be able to connect reliably to the grid, they also needed to have deliverability.

And so, as we think, then, about using the transmission planning process for this, we have to build into the planning objectives not only 33 percent energy on an annual basis by 2020, but the resources that are going to provide that energy are also needed to be deliverable, which means we perform deliverability studies and find out what network upgrades it takes to do that.

Now, there's a lot of -- I think there's a certain amount of confusion about what the deliverability process is and the study process is -- but just to say a few words on that, the ultimate source of deliverability goes back to the origin of the Resource Adequacy Program, what it was intended for.  A very traditional kind of concept that, in terms of the capacity that you have on the system, able to operate, available for operation, it needs to be a quantity in total for the system that's an estimate of your forecast peak load for the year in question plus a planning reserve margin.  In the current rules, it's 15-17 percent margin above the peak load, so you take this 115-117 percent of peak load as a target, each load serving entity has a responsibility to procure their share of it.  But basically it's a concept that adds up megawatts of capacity based on the notion that, when you hit those peak load conditions, stressed system conditions, you can dispatch all of the resource adequacy capacity in an area in order to be able to meet the peak load without overloading any transmission facilities.

Now, I go back to the idea of studying one area of the grid at a time, in an electrical area we take that area and we look at all the resources, including interconnection requests, that are going to be impacting a certain set of transmission facilities, and we plug in a peak load for the system, and then we try to dispatch all of the deliverable generation in that area, including existing RA, as well as the ones that have requested to be deliverable, try to dispatch it all, and see if it overloads any transmission. And if it does, then that's a signal that we need delivery network upgrades.

So it's that kind of a criterion that is really the basis of this. It really says, "Dispatch all the resource adequacy, or all the deliverable generation at the same time, and don't create overloads." That's the standard that we're trying to achieve.

So now, as we go into transmission planning with this, we take both, we take 33 percent energy on an annual basis and the resources that are going to provide that 33 percent energy have to be deliverable, they have to pass that test. So, in the transmission planning process, as we set up how we work on this problem of 33 percent renewable energy as a planning objective, and that's where during 2010, as we were developing that proposal, we worked closely with CPUC staff and came to this notion of looking at portfolios of generation, where each portfolio represents sufficient renewable generation to meet 33 percent renewable energy, and also a particular scenario of how the generation is likely to develop; in other words, how much is internal to the ISO grid and which parts of the grid, how much might be distributed generation, how much might be imports. So that portfolio represents not necessarily the absolutely 100 percent certain one that's going to happen, but a very likely and plausible one that could happen, and then, in addition, we have alternatives. And by looking at alternative scenarios, we get a sense of, well, what's the transmission that it makes sense to build given these uncertainties.

So the essence of being able to do what we're doing, both in transmission planning and in this new generator interconnection transmission planning integration, goes back to the formulation of the resource portfolios, because we are going to take the base case portfolio, and we're going to take a couple of the variations on that, the other portfolios, and we're going to look at what transmission is needed to achieve these two objectives, 1) get 33 percent renewable energy on an annual basis, and 2) have those resources be deliverable for resource adequacy purposes. So we start with the portfolios, put in these planning objectives, identify the transmission that's needed to meet the planning objectives, and then you create a certain amount of capacity on the grid which is able to provide deliverability for a certain megawatt quantity of new generation in each of the electrical study areas of the grid. So we create that capacity through identifying network upgrades, the next step, then, is, well, how does that get allocated if you've got 8,000 megawatts of resources that want deliverability in any area, and the portfolio says we're creating up to 4,000 megawatts of deliverability, how do we decide, well, which of those projects gets the 4,000 megawatts, and which ones don't, because that allocation process, then, is going to decide which of the projects under development will get its interconnection needs met largely through ratepayer funded transmission. Others, if they want to continue, will have to -- will expect to have to fund some of their upgrades without ratepayer reimbursement.

So I'm flipping to Slide 4, and then I'll wrap this up fairly quickly. Just to an overview of how this new structure works, and this would be the new GIDAP, we still have a Phase 1 and a Phase 2 in the interconnection process, as we have all along, but instead of putting 100 percent of the interconnection queue into Phase 1 for studying large area upgrades, we're going to just study a reasonable quantity, and we have some formulaic approach for what that means, exactly, but if you get into an area where we look at the transmission planning resource portfolio, and it says we expect about 2,000 megawatts of generation in this area, and the queue has 5,000 megawatts, we'll say, well, 5,000 is really not likely to materialize, but we may study 50 percent more than what the transmission planning portfolio says, so instead of 2,000, we'll study 3,000, or maybe 2,700, the idea being use this Phase 1 to provide the information what if procurement exceeds the 2,000 megawatts that we're planning for in the scenario. What would be the next significant size network upgrade that we would have to build? And so it gives an idea of what the consequences are of increasing procurement in that area.

Then, each project in the queue, in the queue cluster, has to make a choice if they decide they're going to go into Phase 2 or not. And the choice they make is to pick Option A or B, where Option A says "my project is really only going forward if I get this deliverability at ratepayer expense," the ratepayer funded transmission capacity, "because if I have to pay for that myself, my project is not viable." And we have a number of ways we built in incentives for parties to make truthful assertions because of the consequences --

make that choice. And that way, Option B is my project can go ahead either way because I have deep pockets, I have a large corporate balance sheet, I really think this is a fabulous project, I'll worry about a PPA later, and I'm willing to pay for my upgrades. And then, on that basis, when we go into the Phase 2 process, now we are only going to identify large area network upgrades for the Option B projects because we're assuming all the Option A projects are getting taken care under the transmission plan. So these two steps, 1) give us more realistic results coming out of the study process, and 2) allow developers to make business decisions as to which trajectory they want to take based on what they think are the capabilities of their project. And then, finally, we get down to an allocation, once all of this -- once the Phase 2 study process is done, we have both the Option A and Option B projects could be eligible to receive this ratepayer funded deliverability, but we're now putting scores on all of these projects based on development milestones, and we have a whole list of milestones and degrees to which they've accomplished things, so that what we're trying to do is the ones that really look most viable at the time of the allocation process.

The next thing I'll do in about the two minutes I have left is just let you make a few comments about diagram, which is the flow diagram over what the integrated process looks like on a three-year cycle.

So the top half is the transmission planning process, it's an annual process, but the total cycle is 15 minutes -- 15 miles! Wow, that's fast! Before you know it, you blink, you missed it, right? Don't stop for coffee -- so it's 15 months which starts -- so the yellow box is one whole planning cycle, and the orange is another whole planning cycle -- so it starts with the Phase 1 that I described, where we come up with the planning assumptions, the policy objectives, make a study plan, and then 15 months later, when we take a final comprehensive plan to our Board of Governors for approval. So that's that process.

Then, when you get to the interconnection process, start with the green boxes because that's the first cycle, the first cluster that will go forward under the new rules. So we have -- it's cluster 5, the light blue above it is clusters 3 and 4, which are finishing up under the old rules. But Cluster 5, we have a window to put in requests, we have a Phase 1 study process that goes to around the end of December, then we have this 120-day period in the middle where projects decide do they want to pick Option A or Option B, we go into a Phase 2 study process, then we have an allocation process.

So roughly in terms of the timeline for interconnection, it's approximately the same as it is today, but the study results are more realistic and, when we come out of it, many projects know that they are getting their deliverability needs taken care of through ratepayer funded transmission; other ones know that they don't.

The one last thing that I'll mention, which is not illustrated on here, but the deliverability for Distributed Generation Initiative that I mentioned at the beginning, which we're taking to our Board this week on Wednesday, that sort of fits in the middle here, right around the end of the Phase 1 study process -- I'm not sure -- yeah, here's an arrow -- so it starts around here, the end of the Phase 1 study process, it goes through around February and puts out results of megawatt quantities of distributed generation that could be deliverable at each network node on the ISO grid -- not every node, but we start with a set of nodes identified in the transmission planning portfolio. And then, in the next several months, moving into and parallel with the Phase 2 study, the deliverability megawatts at each node can be allocated out to the regulatory authorities that oversee procurement by load serving entities. So that also is coordinated and fits into the structure of this diagram.

And I think, with that, I've used up my time, so the rest is questions if folks want them. Stopping now, or keep going?

CHAIRMAN WEISENMILLER: Yeah, I've got a couple. The first is would you give us the definition of deliverability for RA in terms of under what conditions a project must be deliverable?

DR. KRISTOV: Yeah, well, deliverability for RA essentially means that, during the peak system hours, peak load hours for the entire ISO grid, that we can deliver the energy from the deliverable resources to the aggregate of load. And what that typically means in our test process is that, if we dispatched all of the deliverable resources up to their qualifying capacity, or thereabouts, that we're not creating overloads on the transmission system; then, we find them deliverable.

CHAIRMAN WEISENMILLER: Okay. Now, is that the top 10 percent? Top five hours? What's the band -- the peak?

DR. KRISTOV: It's generally based on the peak load forecast -- I think it's the peak load forecast because this is annual over a time horizon, so it'll be a peak forecast under -- is it the 1 and 2, or the 1 and 5?

And I'm not sure which one it is, but it's one of those.

CHAIRMAN WEISENMILLER: Okay. And Suzanne showed on page -- on her slide 7 -- the sort of ISO interconnection queue and WDAT queue for June and April. I'm sort of curious on what the current numbers look like. How are we doing in terms of clearing out the existing queues?

DR. KRISTOV: Clearing out the existing queue is a relatively slow process because we're operating under the old rules and the old tariffs, so we have a queue management effort where letters are being sent and communications with projects that are appearing to miss deadlines that are in their GIAs, but in terms of volume of megawatts being cleared out, it's not that high just yet. We also had a new cluster come in, Cluster 5, and we got something like 17,000 megawatts of requests come in there; I don't know what percentage is renewable, but that would add onto that 57,000.

CHAIRMAN WEISENMILLER: Yeah, that's what I was assuming. It seems like, conceptually, part of the problem is that, when you look at the utility of renewable bids, that typically they're finding 10:20:1 ratios between what's being bid and what they need, and obviously some of those are multiple bids from the same project, and some of those are projects bidding to multiple utilities. But, again, it's probably at least a 10:1 ratio of what's going into the interconnection queue vs., quote unquote, "what's needed." And so part of the problem is how -- and, I mean, I don't think that law of economics is going to change, and so the question, in part, is how do we deal with that in the interconnection process where you're always going to be requesting, say, that it have 10 times as much interconnected as you possibly need, or probably that you can possibly accommodate.

DR. KRISTOV: Well, that's right, and that's why with the reforms, I didn't get into a lot of detail, but in how we do the study process, rather than plug in all of those requests and then generate really exorbitant needs for network upgrades in the hundreds of millions of dollars of costs, what we're trying to do is take the volume that's in the transmission plan portfolio and just add a margin on top of that, another several hundred megawatts that would trigger the next network upgrade.

CHAIRMAN WEISENMILLER: Okay. Mike, do you have any?

COMMISSIONER FLORIO: Yeah. Once someone enters into a generator interconnection agreement with the ISO, are those fixed for all time? Or can -- first of all, does it specify exactly what the transmission will be? Or does it just say we'll build transmission to make you deliverable?

DR. KRISTOV: No, it specifies all the network upgrades that the interconnection customer is responsible for. Now, responsible could mean just posting money and getting it paid back later, but it has -- here are the conditions on which you become deliverable, so that is you achieve your commercial operation, these network upgrades are in-service, and there's what we call "plan of service," which is a schedule of when those things are going to be built. So that's all in the interconnection agreement. And those things can be changed. Interconnection agreements can be amended and there are reasons why they are. And under the new proposal we're putting in, there are certain ways, certain flexibilities that we've built in for developers to sign an interconnection agreement with still some uncertainty, and then, within the next year revise it again, and it has to do with that allocation of deliverability.

COMMISSIONER FLORIO: Okay, because, I mean, you have a number of interconnection agreements out there and those may imply greater transmission development than we could pay for, so how does that sort itself out?

DR. KRISTOV: Well, that's the reality that we're living with, which is that possibility that, if all of the stuff goes ahead and gets built, well, what do we do transmission-wise? One of the ways that we're trying to deal with existing queue, and we did this through a Technical Bulletin we put out in January changing the study approach and the network upgrade requirements for existing interconnection queue, and that is everything up through Cluster 4, whereby we're providing the information based on what comes out of the transmission plan as to how much generation can be accommodated in each study area of the grid.

And we had a report that focused specifically on the Southern California, San Diego, and Edison areas, the Western Desert area, that said how much can be procured in this area without triggering the next costly network upgrade, and so that's a megawatt quantity. And then that's information to the load serving entities, to the PUC, to say, "Well, now you look at the procurement and look at how much you're approving in those areas," because it's really going to be your approval of projects that now can go beyond the threshold and trigger the need for a new network upgrade. And so I understand in the -- I think it was in a signed Commissioner ruling in the renewable proceeding that came out around April -- there is a proposal in there for how the PUC would conduct the process to look at the short lists of load serving entities and use the information that comes out of the ISO's deliverability study that says how many megawatts is available in each electrical area, to try to provide guidance back to the load serving entities to coordinate procurement, so as not to trigger these upgrades. So it's that really coordinated management; we're providing that information, but it's really going to be the PPAs that may drive more development.

COMMISSIONER FLORIO: And that information is in this Technical Bulletin?

DR. KRISTOV: Yeah, there's a Technical Bulletin January 31st, I can email you the links, and then there was a Technical Study Report that came out at the same time, which had additional engineering details on this desert area and what facilities we assumed were in, what facilities we assumed were out, and what are the megawatt limits that could be deliverable.

COMMISSIONER FLORIO: Great. Thank you.

CHAIRMAN WEISENMILLER: Could you submit that for our docket, that letter and bulletin?

DR. KRISTOV: Oh, sure.

CHAIRMAN WEISENMILLER: Okay, thanks.

COMMISSIONER PETERMAN: One more question, up here, one more question.

DR. KRISTOV: Yes.

COMMISSIONER PETERMAN: What is your expectation, or do you have an expectation about how many projects will take advantage of Option B?

DR. KRISTOV: Well, we have no information about that, specifically, but my expectation is that it's probably going to be pretty few. I think that, you know, a party has to have really pretty substantial financial wherewithal in order to be willing to take on the uncertainties of being fully responsible for their upgrades. To a large extent -- I'll be frank about this -- the Option B needs to be in our proposal for reasons of open access because, if we're saying the only way you get deliverability is through this rationing method, then it kind of eliminates the possibility of a party being willing to do it themselves, so we are allowing that possibility in a way that we think is reasonable, and maybe one or two will take advantage of it, I don't expect much.

COMMISSIONER PETERMAN: Are there particular incentives we can offer, or that can be offered, to encourage people to take advantage of Option B?

DR. KRISTOV: Well, other than something that subsidizes their potential costs, it's hard to see what that would be because ultimately it does come down to having to foot the bill, you know.

COMMISSIONER PETERMAN: Thank you.

DR. KRISTOV: You're welcome.

MS. KOROSEC: Our next speaker is Kevin Dudney from the PUC, and Kevin is participating via the WebEx. Kevin, your line is open and I'll go ahead and do your slides for you if you just tell me when to switch them.

MR. DUDNEY: Sure. Good morning, everybody. Can you hear me clearly?

MS. KOROSEC: Yes.

MR. DUDNEY: Great, thanks. So my task today is to briefly explain the portfolios that the PUC and CEC have jointly proposed for use in the ISO's 2012-2013 transmission planning process. So these proposals -- or these portfolios -- were proposed in late March and were presented at an ISO stakeholder meeting on April 2nd. The three agencies received comments on those portfolios in the middle of April, and are currently considering whether or not to make any changes to those portfolios. So, go ahead and advance to the next slide.

So briefly, I'll just go through the context for the portfolios and -- flip again, next one -- so one of the key goals of the PUC's coordination with the ISO in the transmission planning process is really to enable the transmission permitting process at the PUC to run smoothly and have all this transmission. So the PUC has the responsibility to provide permits for IOU proposed transmission facilities, and that permitting process must consider the need for the project and, importantly, through an alternative analysis. Next slide, please.

So in order to coordinate these two planning processes, the PUC and the ISO signed a Memorandum of Understanding, I guess two years ago, that commits to closer coordination between the resource planning and the transmission planning process. So resource planning, what I really mean, is the long term procurement planning process at the PUC. And the transmission planning is, of course, the ISO processes that Lorenzo just described.

So the PUC goal, as I see it, is very similar to some of the things Lorenzo just commented about on holistic planning. We need to make sure that the transmission planning process provides the need analysis that is really necessary for the transmission permitting phase at the PUC to proceed smoothly. Go ahead.

So the way we developed these portfolios is using a spreadsheet model that we refer to as the 33 Percent RPS Calculator. The 33 Percent Calculator was originally developed by a consulting group, Energy and Environmental Economics, or E3, for the PUC's Energy Division. Go ahead.

So the basic mechanism of the calculator is that there's -- it's a bottom up model, there are many many projects in there, both based on real specific projects, or based on generic potential estimates done by the Renewal Energy Transmission Initiative, or other studies.  And each project is scored based on four scoring criteria, the net cost score, an environmental score, commercial interest score, and a permitting score. And the first three of these were used in the earlier versions of the calculator, including the 2010 Long Term Procurement Plan, and the recently completed 2011-2012 Transmission Planning Process at the ISO.  The fourth, the permitting score, is something that we created new this year that replaced the previous timing score.  It also made significant revisions to how the environmental score is calculated -- I believe Roger Johnson, who will be the next presenter, will talk in a fair amount of detail about that environmental score.  We also made important changes to how the commercial interest score is calculated.  The final score that is used to rank a project is a weighted average of the four individual scores.

Now, on the next slide, I'll talk a little bit about one important exception to that point, and that is the concept called the Discounted Core.  The Discounted Core is a list of projects that are considered highly likely to go on line, and these projects are included in all of the portfolios generated by the 33 Percent RPS Calculator, unless they prompt new transmission. And the details on the slide here, I'm not going to go over, but the point is that, even if a Discounted Core project would require new transmission, there is a test for whether or not that project is included in the portfolio.

So, going ahead, I'll talk briefly about some of the major updates -- one more slide -- that we've made in the model this year. So many of these are simply an effort to refresh and update the data that underlies the calculator. So, first one looked at a new Renewables Net Short, so specifically the Net Short in 2022, we estimated at 45 terawatt hours of renewable energy, and that's down from a net short of 54 terawatt hours in 2020 in the previous version. The major differences there are the slight decrease in the load forecast and some changes in the RPS legislation that removed certain exemptions for (indiscernible).

The next major update that we did was we looked at some of the capital costs for solar photovoltaic resources and decreased by 30 percent. Third, based on advice from the ISO Transmission Engineers, we observed that the fair amount CREZ identified by RETI shares a lot of the same transmission characteristics as the Tehachapi

CREZ, and for that purpose, we want the two CREZs together under the label "Tehachapi" for purposes of this version of the model.

The most important update we did was to update the lists of renewable energy projects that are available to the calculator in order to develop these portfolios. We looked at -- we updated the information from the commercial projects based on information we have from the three utilities and their procurement processes, and that is the primary projects list. In that process, we defined a new definition for the Discounted Core that I discussed earlier, and that definition is having an approved PPA by the PUC, or other regulatory body, plus having an approved major environmental permit. So that's a pretty strict test in order to be considered a Discounted Core project. And we changed the definition of Commercial Interest Projects, which have a good commercial interest score. We added a new list of small solar PV projects located on the distribution grid, based on a potentials study done by E3, and we added a new data source, the Renewable Energy Action Team, REAT, is a group of State agencies that tracks renewable energy projects in their permitting process, so we used that as a source of projects that are in permitting, but aren't necessarily in PPAs -- that don't have a PPA with one of the three IOUs.

Finally, we updated the environmental and permitting scores and, again, Roger will talk about those. Go ahead. One more. Great. So the PUC and CEC proposed four portfolios for study in the 2012-2013 Transmission Planning, first, the Cost Case, which the two agencies proposed as the base case, it minimizes the cost of renewable generation and transmission, so that's a net cost concept that is intended to include all of the transmission and appropriate distribution upgrades necessary to incorporate the generation. It also credits the generation project for any capacity benefits, specifically resource adequacy. It also credits the generation projects for the value of the energy that it would produce.

The second portfolio proposed is an environment portfolio that basically selects for projects on preferred locations. Third was a commercial interest portfolio that gives preference to projects that meet the test for being a commercial interest project, which is, again, having a PPA, an executed PPA, regardless of whether or not it's been approved, plus a complete application for its major environmental permit.

Four was a high distributed generation portfolio, and that one is designed to include additional small solar photovoltaics in locations near load, and those are PV resources on the distribution system. We created that portfolio by including additional resources in the Discounted Core that would basically represent a policy choice to change our RPS contracting direction in favor of distributed resources by adding to the RAM program, or other procurement programs like that. Okay, go ahead.

And this slide gives a high level overview of the four portfolios proposed. This is a breakdown of the portfolios by technologies towards the bottom, the middle section of the table shows a breakdown of the portfolios as Discounted Core Projects, Commercial Interest Projects that are not in the Discounted Core, and the Generic Projects, again, the Generic Projects are potential estimates from efforts like the RETI Initiative, as well as the REAT projects that are in permitting, but do not have PPAs.

So a couple of points about this slide; again, notice the Net Short is the second line from the top, 45 terawatt hours in 2022 for renewable generation. Just to provide a point of comparison to some of the numbers discussed earlier, these four portfolios range from 16.8 gigawatts to just under 18 gigawatts of renewables, compare that to the size of the queue that was being discussed earlier.

And then a final point about this is the very bottom line is labeled New Transmission Segments, so, importantly, only one of these four portfolios shows a need based on the simplifying assumptions in the 33 Percent RPS Calculator, only the Commercial Interest Case shows the Kramer transmission as being necessary. So what major new transmission means in the context of the calculator is that there's simply a cap on the amount of generation that can be identified within each CREZ before that CREZ shows a need for new transmission. So only the Kramer CREZ in the Commercial Interest case shows a need for new transmission and that project would be something similar to the Cool Water Lugo, or other south of Kramer project. Okay, go on to the next slide, please.

One of the important comments from many stakeholders was that these portfolios showed a lot of non-CREZ resources. This table is an attempt to identify the county of origin of those non-CREZ resources. Next.

And I will just wrap up by showing some of our work towards future scenario development. The PUC staff recently held a workshop in April to brainstorm with parties about how these scenarios should be developed, and then, last week, the PUC staff published a straw proposal about this, and we will have a workshop this

Thursday, May 17th, in the PUC auditorium. The primary forum for that discussion is our 1203014, which is the 2012 Long Term Procurement Plan Rulemaking. We've also announced this workshop to the RPS Service List, and encourage anyone interested in the audience today to come join us at that workshop on Thursday to discuss how we would develop these portfolios in the future. Thank you very much, and I'm now open for questions.

COMMISSIONER PETERMAN: Thank you. This is Commissioner Peterman here. A couple questions primarily related to the Portfolio Summary. I'm interested in having a better understanding of what was considered as environmentally preferred generation, what were those criteria. When looking at the summary, I see that in that case you have a significant decline in large-scale solar PV, but slower thermal generation staying constant, and then an increase in wind.

MR. DUDNEY: Sure. I think I will largely ask you to defer that question to Roger Johnson, who will present next, but the high level answer to that is that, we, the PUC staff, worked with the Energy Commission staff to identify projects in preferred locations, so the Energy Commission staff categorized locations based on environmental preference using information from the DRECP and other sources.

COMMISSIONER PETERMAN: Thank you.

MR. DUDNEY: Sure.

CHAIRMAN WEISENMILLER: Yeah. Kevin, this is Bob Weisenmiller. I was going to ask you to talk about the treatment of the non-CREZ projects in terms of transmission cost, and how we might change that.

MR. DUDNEY: Okay. One important assumption for non-CREZ resources is that they fit on existing transmission, that's not necessarily the same as that they have no transmission cost. You can -- for those interested -- you can look into the details of the calculator and see that transmission and interconnection costs are calculated separately. But, for the most part, non-CREZ resources -- all of the non-CREZ resources have the assumption that they fit on existing transmission. That generally leads to a very low estimate of the transmission costs. This was a point of some concern, I think both for the agencies involved, as well as many of the stakeholders. The one attempt that I think is likely to be raised in the changes to the portfolio, that Chair Weisenmiller and Commissioner Florio may propose, is to re-categorize some of the non-CREZ resources into the CREZs that make sense from a transmission perspective. So, for instance, if a resource is just outside of the Tehachapi CREZ, but would share the transmission upgrades and just interconnect to the transmission system at the same point as a lot of the Tehachapi resources, we would hope to consider that resource in the Tehachapi CREZ for purposes of this portfolio update. Now, it's my anticipation that that update will pretty dramatically reduce these non-CREZ numbers from -- in these earlier portfolios, I think 3,000 to almost 7,000 megawatts, down to less than 1,000 megawatts in each of the four portfolios.

Another aspect to that update that we're working on is actually identifying a couple of new transmission zones that were not identified by RETI, but share similar transmission, and we will be adding those to the CREZ list in the 33 Percent RPS Calculator for this update, just to better, I guess, consider the transmission realities in the California Central Valley and group some of those non-CREZ resources to share transmission and ultimately they'll look exactly like a CREZ on some of the other summary tables shown.

CHAIRMAN WEISENMILLER: Okay, thanks. The other question I had was, obviously this is the first time we've really tried to do a high DG case, and so I guess part of the question was a sense of what improvements we'd want to do between now and the next one.

MR. DUDNEY: Well, the first comment on that is that, in the Environment case in the previous iteration actually had quite a lot of distributed generation included in it, and that was, I think, largely based on some of the environmental assumptions surrounding some of the potential projects there. In this case, the major improvement we've done is used a newer study done by E3 that is designed to look at the potential for renewable generation around each substation, where the transmission grid meets the distribution grid. Now, the specific test that E3 used, at least for the version of the study that we implemented for this, is to limit the amount of distributed generation at each substation, such that in all 8,760 hours of the year, the total distributed generation is less than the hourly load on each -- on that substation. So that's sometimes referred to as the "No Backflow Criterion," and that's really the major improvement is that is a newer dataset that shows the distributed generation in places where it is always less than load. For the most part, that has the effect of moving the photovoltaic generation from areas in the desert where the distribution system is not as strong and potentially major transmission upgrades were being shown needed to support these distributed resources, and instead moves these resources to the coast where the distribution system is, in many cases, stronger and it's less likely that transmission upgrades will be necessary in order to deliver those resources to load. Does that answer your question?

CHAIRMAN WEISENMILLER: Yeah, thanks.

MS. KOROSEC: All right, thank you, Kevin. Our next speaker will be Roger Johnson from the Energy Commission.

MR. JOHNSON: Good morning, Commissioners. Roger Johnson with the Energy Commission. I'd like to talk about the work we did with the PUC on the environmental scoring for the scenarios.

Orderly development of renewable energy has been determined as something we need to do to improve the development of our world class renewable resources, while minimizing the need for new transmission infrastructure and the associated environmental impacts. So the Desert Renewable Energy Conservation Plan is providing that direction. The DRECP is being developed by the Renewable Energy Action Team, which was developed by an MOU -- excuse me, by an Executive Order -- from Governor Schwarzenegger, and that Renewable Action Team is comprised of the Energy Commission, California Department of Fish and Game, the Bureau of Land Management, and the United States Fish & Wildlife Service. And together today with the cooperation with the PUC, the State Lands Commission, the ISO, and the Department of Defense, the Renewable Action Team is working on the DRECP.

DRECP needs to be integrated into this long term planning process for renewable energy. The DRECP will provide binding long term endangered species permit assurances while facilitating the review and approval of renewable energy projects in the Mojave and Colorado Deserts. DRECP is specific to the deserts, only. Preferred renewable generation areas and associated transmission corridors are being identified in the DRECP now.

The CEC and the PUC now believe that the land use assumptions and the natural resource data being developed in this stakeholder process, State, Federal, and Local stakeholders, should be integrated into the LTTP process, the Long Term Planning Process.

So the Environmental Scoring Methodology was developed to incorporate this new information that's been developed in the DRECP, which when the original RPS model was developed for the PUC, it was limited to using information that was available at that time and that was based upon the RETI process, Renewable Energy Transmission Initiative, and the environmental information was quite generic and not consistent throughout the desert, but it was the best we had at the time. But now we've been studying the desert and we have a tremendous amount of information now on the environmental preferences of locations in the desert where essentially the desert has been described in areas of high environmental sensitivity and low environmental sensitivity, and those low environmental sensitivity areas is where the DRECP has been focusing efforts to identify renewable generation areas and transmission.

The scores are based on a combination of positive preferences for certain areas. The DRECP has developed these renewable energy study areas, which were, again, considered to be lower environmental quality areas in the desert. Some of these are previously agricultural areas that have been abandoned, and then there's also disturbed lands in the desert and elsewhere in the state that were identified for scoring. A negative or high worse score was given for non-renewable energy study areas, but within the DRECP boundary.

So the DRECP boundary is essentially 22 million acres of the desert. The DRECP identified five renewable energy study areas, and so projects that were located physically in these study areas were given a score, a preferred environmental score, vs. projects that were outside of those study areas, which tended to be higher environmentally sensitive areas. Neutral scores were assigned to projects on non-desert non-disturbed lands, and then rooftop mounted DG projects were assigned the best lowest score, regardless of location.

So all projects needed to have their unique PUC ID numbers linked to a latitude-longitude before they could be backed by the CEC cartography unit, so latitude, longitude data was provided by the PUC. The Energy Commission also had, as Kevin mentioned, the Renewable Energy Action Team list of projects. This list is all renewable projects in the state that we're aware of, that are under some permit evaluation; they don't have their permits and they don't have PPAs, necessarily, but they're either local land use projects where the counties are permitting them, or the Renewable Energy Action Team is reviewing those projects. So now all of the projects have been identified with geographic locations and could be scored.

So we ended up with 2,366 data points and the scoring was performed on those. This diagram shows the DRECP area, the large area of the desert, and then the renewable energy study areas are these purple crayon areas, there was five of them that were originally developed for the draft that was released last month. Since that time, the Renewable Energy Action Team has now focused in on these renewable energy study areas and developed more refined areas called "Development Focus Areas," DFAs. And so today, about 90 percent of the new DFAs are located within the original renewable energy study areas. So there could be 10 percent of the projects that 10 percent of the projects in the DRECP that now aren't in what we originally scored as a renewable energy study area, so that's something that would be determined when you see the final alternatives, but primarily, most of the projects that we've scored, the scoring is still good as far as giving them a preferred score for being in a renewable energy study area.

So at one time, we also created a KMZ file of all these projects so that we could use Google Earth to ground truth these projects, determine whether or not they were on disturbed lands. In the Central Valley, there were a lot of salt affected soils that we considered to be preferred areas, as for projects that were given a score if they were on salt affected soils vs. prime Ag land. And then, in the desert, as you can see from the outline, the projects that are within the purple crayon received a better score than the projects that were identified outside the purple crayon.

So the environmental scoring matrix, this is how it came out, there were five categories and the first one was, "Was it DG? No. Was it in the DRECP? Yes." So, "Was on disturbed lands in the DRECP? No. Was it in the renewable study area? Yes." And so, with those criteria, it received a score of 25. In the second category, again, DG, no, in the DRECP, yes, on disturbed lands, no. Was it in the study area? No. And here it received a poor score of 80. The next category, DG, no, in the DRECP, no, disturbed lands, no. Was it in a renewable study area? No. So this is the neutral score that was given to all projects outside the DRECP, projects on productive Ag lands, including ground mounted PV outside the DRECP, and any project unable to score individually and all non-California projects.

The fourth category, again, not DG, in the DRECP, wasn't applicable, was it on disturbed lands? Yes. And in the RSA, again, not applicable. So projects that were determined to be on disturbed lands were given a preferred score of 20, and this included ground mounted PV on abandoned Ag lands, closed facilities, closed mines, disturbed and degraded lands. And finally, the last score, was it a DG project? Yes. If it was rooftop solar, solar PV located as a shade structure in parking lots, ground mounted PV at wastewater treatment plants, it was given the best score of zero.

And that's how we did the environmental scoring. I'm available for questions.

COMMISSIONER PETERMAN: Hi, Roger. Thank you. Thank you for clarifying for me what's included in the environmental matrix. More of an observation than a question, it seems like the environmental scoring matrix appropriately incorporates the more extensive data that's been collected in the DRECP, but that going forward there is more data that could be available and beneficial for looking at projects outside of the DRECP area. In particular, I don't think the matrix necessarily identifies preferred sites for biogas or biomass, where the focus seems to be primarily on solar PV. So I don't know if you have any comments on that, but that's just going forward, next steps, that's an area I think could use some more information.

MR. JOHNSON: That’s a good point. We are looking to see if we can develop better information throughout the state for environmental concern and use that information for scoring the physical locations of future projects.

COMMISSIONER PETERMAN: Thank you. I'll just add that we had our first workshop for the renewable strategic plan, was looking at some of the other environmental benefits from certain types of renewables, and one of the issues that came up was the potential for fire hazard reduction, for example, as an environmental benefit that certain biomass facilities provide. And it's my understanding that would not be captured in this scoring matrix currently.

MR. JOHNSON: Correct. This scoring matrix is only applicable to the physical location of the projects that we can determine what impact it is having on that geographic area.

COMMISSIONER PETERMAN: Thank you.

CHAIRMAN WEISENMILLER: Yeah, Roger, do you want to describe and point to the number of projects that you identified, I mean, that was part of the work, activity, was to start out with a pretty extensive project list, both for wholesale and DG projects?

MR. JOHNSON: The total number of projects we looked at?

CHAIRMAN WEISENMILLER: Yeah.

MR. JOHNSON: Oh, I don't have that number, but I can develop it for you. We ended up scoring --

CHAIRMAN WEISENMILLER: Go ahead.

MR. JOHNSON: -- 2,366 -- we had to go through our lists and determine where duplicate projects existed and remove those, and ended up with a total list of the 2,366.

CHAIRMAN WEISENMILLER: And that was how many megawatts, roughly?

MR. JOHNSON: Kevin, are you still on?

CHAIRMAN WEISENMILLER: Actually, you could submit it. I guess the other thing that would certainly help our record is, you know, you've given us the great maps of projects, and so -- and I guess this is one here, but anyway, if you can submit the sort of project list --

MR. JOHNSON: Yes, we will.

CHAIRMAN WEISENMILLER: -- I assume that would help the public.

MR. JOHNSON: Be happy to.

MS. KOROSEC: All right, next we'll move into our panel discussion, so I'd like to -- excuse me, Mark?

MR. HESTERS: As people are moving around, there' a hole in the floor right here, just be careful. A heel caught in that could break an ankle.

MS. KOROSEC: All right. Can we have the first panelists come up to the table, please, and I'll introduce our Moderator -- our Safety Coordinator, Mark Hesters.

COMMISSIONER PETERMAN: Yeah, do you just want to put like a binder or something on top of that hole? As the panelists come up, I just want to say thank you in advance, and of course, I'll say thank you afterwards for your participation. I know all of you have very busy schedules and having your input into our record is incredibly valuable. So thank you for taking the time.

MR. HESTERS: Was everyone able to find their place? Good. Good morning. My name is Mark Hesters. I sort of worked to coordinate this panel. We have nine panelists, mostly from the utilities industry. We posed six questions originally for the panel. The first three are centered around the resource portfolios that we've discussed some earlier. The last three were more looking at sort of the new ISO process and how -- what types of information needs were required from both the generators and the utilities to make that process work smoothly and efficiently.

We've asked each panelist to limit their presentation to two slides and five minutes. We don't have that many slides, most people -- it's probably more efficient to go five minutes without slides. I wasn't certain whether Commissioners wanted to ask questions of each panelist as we go, or wait to the end.

COMMISSIONER PETERMAN: I'll say I don't think we're going to be shy to interject when we have a question, so we'll just pop to the microphone, but otherwise, please, lead as you wish and we'll listen. I think we'll let the panelists go so that we have an opportunity to hear from everyone.

MR. HESTERS: Okay, well, let's start with our first panelist, which is Carl Silsbee from Southern California Edison.

MR. SILSBEE: Good morning, Commissioners, staff, and fellow workshop participants. I'm pleased to have an opportunity to provide comments today. I manage SCE's involvement in the CPUC's Long Term Planning Process, the LTPP Proceeding, among my various resource planning responsibilities. So I'm going to spend much of my time this morning talking about the role of the scenarios that we've talked about earlier today in infrastructure and resource planning. There's a colleague of mine on a panel this afternoon who can talk a little bit more on interconnection issues.

I would like to make several brief comments on interconnection topics, however. We've supported RETI, we've supported the DRECP, and we've supported the various interconnection reforms that have taken place over the last few years. While the process is still far from perfect, we do see it as improving and, from our perspective, we intend to continue to try to work within the various agencies' efforts to improve the process even more so. In hindsight, the rapid rush to 20 percent and then to 33 percent RPS has really stressed the process by which we have followed to acquire and site renewable resources. And that rush has created a lot of the unfortunate difficulties that we faced in the last few years, and even today.

As we close in on 33 percent by 2020, I hope we'll take advantage of having gotten through the rush to the grid to step back and take stock of what has worked and what hasn't. I think we've got, going forward, a little more opportunity to reason through what the best options are going forward, to put in place procedures that will work for the future.

One significant challenge that remains is the disconnect between where developers of small renewable projects propose to locate vs. where our transmission system can accommodate new development without significant additional cost. I think in other forums, we've presented some of what I might call heat maps to you, that get to a description of where we see an opportunity to add smaller projects without significant transmission, and where we do see significant transmission impacts.

We realize that feed-in tariffs are attractive, both to the CEC and the CPUC, because they avoid what's perceived as a burdensome process of competitive solicitation. The down side, however, is that solicitations can include transmission scoring, and thus can be a means -- that transmission scoring can be a means to direct projects to areas where the costs are lower. And so we really need to work through how we can take an open process of feed-in tariffs, and integrate some of these transmission choices so we steer the projects in ways that are less expensive and, I presume, environmentally less harmful.

Let me turn to the scenarios. The CPUC staff proposed standardized planning assumptions containing four scenarios in the 2010 LTTP, the one that just recently concluded. We, the other major IOUs, and the CAISO spent considerable effort to analyze the impacts of these four scenarios on system reliability, on retail electricity cost, and on GHG emissions. The bottom line is that the difference in impact across the four scenarios was relatively modest, and the analysis that we undertook failed to produce any actionable results. So I think that the value of this work has so far proven to be quite limited.

I've often thought through the process that we were creating paralysis through an extensive analysis, without stepping back and really asking ourselves what we were trying to accomplish through that process. So I've looked with some degree of skepticism at the presentation that was given to you this morning about four new scenarios to consider and perhaps analyze. And I'd like to think about a different approach than the one we've undertaken so far.

To begin with, I'd like to think about starting with a base case scenario that most closely resembles the extension of our status quo procurement and interconnection activities, so at least we have a sense of what may happen if we take no further efforts to reform policy. We aren't privy to all the information that was put into the development of the scenarios across the three IOUs, but it seems to us that the commercial interest scenario, which is an extrapolation of signed PPAs and other things that are in the pipeline, so to speak, would be a more appropriate base case than the cost constrained case, which has been identified to the CAISO as the agency's preferred strategy -- excuse me, preferred scenario.

Second, we need to study strategies, not scenarios, and what I mean by that is if we just pick artificial scenarios based on weighting cost by .7 or weighting environmental by .7, it really isn't all that productive of an activity because it's not actionable when we get down to the bottom line.

If we don't like the base case, then we ought to come up with a set of strategies or policies that are intended to take us to a different place, and then use the scenarios to drive the testing of how effective those strategies and policies are in getting us to a different place, that everyone is more comfortable with. We need to recognize the production simulation modeling and transmission analysis models are extremely complex and time consuming to run, so we need to stay very focused on the bottom line and not just run a whole bunch of scenarios because it's nice to run those scenarios; focus is critically important here.

It isn't clear to me whether any of the four scenarios that were talked about this morning are intended to address important policy issues such as the work that Lorenzo Kristov talked about, about changing the manner in which projects are selected through the generation interconnection procedures, or the Governor's local energy resources proposal. If we're going to do something meaningful here, we ought to ask ourselves what are the strategies we're trying to test and develop scenarios that do that.

Now, I am somewhat hopeful; there was a document that the CPUC staff issued last Thursday to kick off the process of planning assumption development and, rather than just include these four scenarios, the PUC staff has suggested an open process involving stakeholder input to build policy-driven scenarios. I'm hoping that will bear fruit and develop a better set of actionable scenarios for us to look at going forward.

The final point is that we haven't yet figured out how to engage the environmental community in an effective process of making tradeoffs among competing environmental goals. We feel extremely constrained in Southern California. The flexible generation plants that we need to balance higher levels of intermittent renewable resources are vexingly difficult to get sited because of things such as PM10 restrictions and the Water Board once-through cooling rule. These power plants produce a de minimus amount of PM10 compared to mobile sources, and yet restrictions in how we get tradeoffs between mobile and stationary sources really are driving us to some conundrums that more effective balancing of environmental tradeoffs would allow us to avoid.

A modest step forward in the near term would be for us, as we do the scenarios, not just to focus on environmental scoring at the front end, but to look at what the results are across the different scenarios in terms of important metrics that people within the environmental community would focus on, so that there's a greater appreciation for how important the distinctions are among the different scenarios. And I realize that's a very challenging activity because there are a lot of different dimensions to what people consider to be environmental impact. All we did in the 2010 LTTP, however, was look at a single metric which was the GHG emissions across the four scenarios, so there's room for us to explore more in that direction. That concludes my remarks. I'm happy to answer questions now, or wait until the end of the panelists.

CHAIRMAN WEISENMILLER: I have just a couple questions. One of them is, in terms of the E3 DG case, how well does that match the Edison perspective of, at least on its system, the interconnection opportunities for DG?

MR. SILSBEE: The one that was released in the letter to the CAISO, I haven't looked at. I think when we look at some of the work that the CEC is doing on the LERs, we do have some significant concerns that a lot of the development there is being targeted to areas, counties in which we see significant delivery challenges through the transmission network.

CHAIRMAN WEISENMILLER: And on the cost constrain case, do you have a sense of how the cost numbers line up with Edison's sense of the cost?

MR. SILSBEE: When we went through this in the

2010 LTTP, we were unable to identify the distribution level impacts across the various scenarios, it was a work in progress. I think we've advanced our thinking there and, as we move forward in the 2012 LTTP, I'm hopeful of trying to get some of that information out and available.

With regard to transmission, frankly, there wasn't any variation, or any significant variation, across the four scenarios in the 2010 LTTP. There might have been if we had done it in 2006 or 2008, but by the time we got to analyzing the scenarios, much of the transmission had already been committed by the CAISO. And, again, it doesn't do us any good to study what might have been, but for the passage of time. So we left the transmission largely intact across those four scenarios.

CHAIRMAN WEISENMILLER: And the generation cost?

MR. SILSBEE: You know, there was a difference in generation cost driven by our then current assumptions as to the cost of various kinds of renewables, that's obviously something that's changed quite a bit in the last few years, I'd have to go back and look at the numbers. Information is available in the record and the PUC 2010 LTTP.

CHAIRMAN WEISENMILLER: Okay. Thanks.

MR. HESTERS: I wanted to make one other point, is we will have time after we're done with the panelists for members of the audience who want to come up and provide -- answer these questions or provide comments, once we're done with the panelists.

So next we have Jason Yan with San Diego Gas & Electric -- PG&E, sorry, Pacific Gas & Electric.

MR. YAN: Hi. Jason Yan from PG&E. I work in the Regulatory Relations Group in FERC and ISO Relations and I mainly cover transmission planning and generator interconnection policy.

So I just wanted to start by saying that the changes that the ISO has approved to integrate the transmission planning process and the generator interconnection process have the potential to really fundamentally change the way that transmission and general interconnection gets planned and built in the state, mainly because of the switch between the cost responsibilities, whereas transmission that would have been identified in the interconnection process would have been upfront funded by generators, it would now just remain their responsibility for a potentially large number of interconnection requests if they were to move forward, and we expect that that will be a very strong incentive or hammer to cull the queue so that it matches better with the procurement process, or at least that's the goal.

So PG&E's goal in this area has been to make sure that we are reaching our renewable procurement and other State policy goals in the most efficient way possible for our customers. We see transmission as an enabler to meeting those goals, rather than an end in and of itself, and recognizing that transmission is still a fairly small, in comparison, part of the cost that gets us to meeting those policies, especially compared to our procurement costs. So when talking about these scenarios that drive the transmission planning process, we favor one -- a scenario that most -- or best matches the commercial realities. So, echoing some of the comments by Edison, we favored a commercial interest scenario as the base case.

It's important to note that the base case that the ISO uses is really the one that drives future transmission planning. The other scenarios, although they are studied, they're really providing information for potential future cycles. But if you're going to approve transmission for some reason, it's got to be identified through the base scenario, at least that's my understanding of the ISO tariff. This framework of thinking about the all-in cost to our customers is something that we look at with respect to DG, as well, so one thing that's also worth noting is that, in the ISO's last planning cycle, they had a high DG scenario and that scenario would have identified more transmission than the other three scenarios, and it's partially because of the way that the DG was identified in those locations; hopefully we can have improvements in the future to that scenario. Now, that doesn't necessarily mean that because more transmission was identified, that there aren't projects in there, large or small, distribution or transmission level, that are cost-effective for our customers, and you really have to take a look at the all-in cost, not necessarily just the transmission interconnection cost that would get us there.

Now, with smaller DG projects, often the interconnection costs can be what makes or breaks the cost competitiveness of a project when you're not bringing large amounts of megawatts to the grid. And so, in looking at the high DG scenarios, we believe that perhaps the no-backflow assumptions that were used might have been too simplistic, and not necessarily identifying the right locations and right sizes. We look forward to working with the PUC and the ISO in the future to help provide information that can identify better places for interconnection so that we can find the places that are least costly for our customers.

We're very encouraged by the PUC's ongoing workshops to help identify changes to the scenarios for future planning processes, that has been probably the biggest roadblock to getting the right plan out there is that the stakeholders have had very little input into what goes into those scenarios and the adjustments between one year and the other.

And lastly, I'd like to say that the coordination among the various interconnection processes, so transmission, distribution, both on the FERC jurisdictional side, and on the PUC jurisdictional Rule 21 side, are very encouraging developments. We look forward to continuing to improve those processes so that those processes are well coordinated and we're helping to make sure that interconnection isn't a roadblock to meeting our policy goals. Thanks.

MR. SPEAR: Good morning. Will Spear from San Diego Gas & Electric, and I appreciate the time also, just like my colleagues.

First off, I'd like to start with some good news, Sunrise is scheduled to be in service in June, which, given the recent events with San Onofre, Sunrise is really going to enhance the reliability of Southern California, and based on the discussion today, it's really going to still take the delivery of renewables into the California ISO. We can go to the first slide.

So based on a conversation with Mark, I broke this up into basically two slides, one to discuss resource scenarios and key uncertainties, and the other slide to discuss the CAISO's new process. The most important point, I think, and it is echoed by PG&E and SCE, is that we need to have -- the Discounted Core should be the nucleus of all these resource scenarios. And we need to formalize a process around updating the Discounted Core. SDG&E has signed contracts, it gets close to the 33 percent goal, and this should be the basis for all our scenarios as we move forward because the projects are not going to get developed unless they have PPAs in place.

Some other things that we noticed, too, that we didn't think the out-of-state transmission requirements were properly defined in the calculator. We thought that projects could get developed and there was a possibility for wheeling it across lines, and I know in the calculator most of the models show that you need to build new transmission to have these projects come to California.

The key uncertainties we see in the future is the long term economic growth impact on -- the impact on electric load growth, the effect of distributed generation, and electric vehicles.

And also some work done by CPPG shows that 50 percent of the gas-fired generation that will be replaced by renewables will be out of state. So what we're going to see in the next few years is a lot of these environmental requirements to retire fossil fuel generation, you're going to have available transmission capacity if we can develop some of these renewables in that area, they could take advantage of the transmission capacity. Next slide.

And this was actually covered very well this morning. I was going to talk a little bit about this, but as SCE and PG&E noted earlier, these recent changes in the interconnection process represent significant improvement. I think everybody is aware that the floodgates were open in the interconnection queue, and San Diego, for an example, had roughly 8,000 megawatts of proposed generation, and our peak is, you know, 4,500 - 5,000 megawatts, so it was not practical to study these.

I know in the last Cluster 1 and 2 studies, that the process was to turn on all generation, a model that all generation would get built and then see how it flows throughout California. That wasn't reasonable and it led to high cost transmission. But I think the new approach is fair, I think we should be using the 33 percent RPS portfolio as the base case to establish the available transmission capacity, and as they noted earlier, anything above that, it would be up to the generators to fund. So ratepayer funded upgrades with positive economic value were also alternatives.

The only other point I would like to make is we do need alignment with the LSEs, State and environmental agencies on siting. A recent project that is underway in San Diego where we're looking for approval is the Eco Substation. This project's main goal was to improve the reliability and to bring renewable generation in East San Diego. There is a tremendous amount of opportunity for wind and solar in that area, and we're right around three years in the process for a PTC, so I thought that was something just to bring up. That's all I've got.

MR. HESTERS: Next, we have Jaime Asbury with Imperial Irrigation District.

MS. ASBURY: Good morning. Jaime Asbury, IID. I'm here to provide a little information about renewable projects that are under development in Imperial County. All of these projects are interconnecting, or proposed interconnection to the IDD system, but they will all seek export from IID to serve load elsewhere.

Our Transitional Cluster was nine projects proposing approximately 930 MW. We've signed

Interconnection Agreements with those projects, the development work to accommodate them; the network upgrades on the IDD system are currently in process. We are developed the EPC packages, the preliminary engineering is underway, right of way assessment, etc. We currently have four projects in preliminary stages of construction, they have PPAs and they're exporting from the system. We have 150 MW of solar slated for SDG&E, and 50 MW of Geothermal that will be exported into Arizona.

How this marries up with the ISO's base case in its 2012-2013 Transmission Plan was that the transitional cluster projects approximately mirrored what was modeled. Next slide, please.

We have additional projects, however, in the interconnection process. We have 26 in our Cluster 1 project. That's approximately 1,700 MW of renewable generation, it's broken up by solar and geo, we have a little bit of wind, and some biomass.

For any resource scenario currently underway or in development, we would just appreciate and encourage that those additional projects be accounted for in any planning process. We do have great interest in the Valley, there's considerable resource there, and we'd just like to see it developed to the extent possible and included in any planning process. That's all that Imperial Irrigation District would like to -- just to let you know what's currently underway in our system.

MR. HESTERS: Any questions?

CHAIRMAN WEISENMILLER: I just wanted to follow-up, I think Commissioner Florio and I both got a letter on Friday from Bill Kissinger on substation cost question where, where again it seems like, along with IID, you've got a lot in the interconnection; certainly, as a matter of State policy, we're trying to do development there, but I guess some of the cost allocation issues are arising to the fore. Do you want to comment on those?

MS. ASBURY: I'm not currently involved in those discussions on behalf of IID and I would certainly -- I can certainly encourage that additional information be provided to you.

CHAIRMAN WEISENMILLER: Okay, well, I think Mike and I would docket, certainly, the letter we got.

MS. ASBURY: Certainly.

MR. HESTERS: Next, we have Chifong Thomas.

MS. THOMAS: Good morning. I'm happy to be here, to be on your panel, for the opportunity to talk to you. So, I'm also, like the utilities, we believe that the ISO's process is a step in the right direction, but much more needs to be done. And we also are very happy that the CEC and the CPUC and the CAISO are working together to come up with resource portfolios and for the transmission planning studies because resource portfolios actually drive the transmission plans.

So the slides are arranged -- they try to answer the six questions that the CEC had posed, and the first question was, you know, which kind of uncertainties should the scenario consider? Well, the uncertainties, of course, one is the margin that you would require for the load growth because it's all a projection anyway, and then the RPS goals, what would they be in the future?

We know that there was 20 percent in 2010, and now it's 33 percent in 2020, and so is it going to be more or less in 2030? Is that something that needs to be considered? And then, of course, all uncertainties are not created equal.

Some uncertainties are more uncertain than others and, so, then, what we're looking at is, if you have resources that already have PPAs and resources that have permits, they should probably be more certain than resources that have neither.

And of course, the whole objective is not to plan the transmission, not to build particular transmission as a goal; the goal is to connect the resources. And so, if we had chosen the wrong scenario and to develop transmission plans around the scenario, and they turn out to be wrong, of course, in planning optimists would say that you are half right sometimes, and half wrong sometimes, and engineers would probably think that you had twice as much transmission as you ever would need. And then, of course, if you look at statistics, in some places you have more transmission and in some places you have less transmission than you need, so therefore you end up equal.

So then the whole thing is that, what should drive the Renewable Calculator? Well, first we should take a look at the objectives; the Renewable Calculator should support the State objectives, should it be greenhouse gas reduction, environmental impact reduction, and also the planning philosophies. This morning we heard that sometimes you want to upsize some transmission line projects in order so that we can build less in the future and, so, if you want to upsize your transmission projects, then the calculator would come in and say, well, the resources that need transmission would not be allowed, then it seems to be a conflict in supporting the objective.

Then, after we set the objectives, let's talk about the design requirements. Obviously, it should be reducing the uncertainty and you also consider planning horizons because there was a 2010 planning horizon vs. 2050 planning horizon, which give you a different set of optimal transmission plans.

Then, also recognize the limitation of the simplified approach because there's a lot that would enter into transmission planning and resource planning, it's a very complex issue, and so by trying to limit the opportunity for resources to be sited, based on a calculator with a simplified approach might be, in the end, not to the ratepayer's interest. So we also need moderate changes because drastic changes from one year to the next, frankly, are not very helpful for planning and investment decision making.

And also, we need realistic assumptions because, you know, some updated information and consistent data. Also, taking into account the advances in future technology, so that the prices that we are seeing today may not be the same prices we're seeing tomorrow and, of course, this all needs to be taken into account. And then we should have some increase in transparency and, so, I'm really happy that we're having this workshop today and the CPUC and staff also are having workshops later to take stakeholder input. Next slide, please.

So a policy goal to be considered basically is RPS objectives, resource diversity, and cost-effective reliability, and reduced emissions. And of course, that would go into the GHG reduction and environmental impacts. And then we also want to identify & address potential areas where, you know, based on technical feasibility, you know, within the planning horizon. And so potential issues, say, for example, if you put in something that you think should occur, however, the supporting technologies are not there, it may not happen in reality.

And so that goes to the RPS and DG Policies. It should consider exactly what kind of supporting technology do we need for implementation? For example, the reliability needs including the programmatic and technology diversity, and also the fact that forecasting and visibility, the communication, and we need to go back to CAISO for operating for reliability, and then the lead time for all this new technology that some of them may not exist yet, so they need to be developed in order for the system to actually operate. Next slide, please.

Then we need to go to the transmission planning process. We're saying that the efficient process, the question was, you know, what we should do for improved -- efficient process. The first and foremost would be the increased coordination between the various agencies, so we consider long-term needs with policy objectives so that we can avoid the potential, you know, you have either long term transmission with fewer upgrades later, or more or shorter term transmission with more upgrades later, but not the near term transmission that would require more upgrade and longer lead time.

And we want to produce information for developers so that they can actually assess where would be a good place to site because, right now, the developers really -- it's not that the fact that they wanted to go site in places that had no transmission and terrible environmental impact, it's because they don't know. So more information would be great.

And then develop some information on how you plan transmission that would be quick because I understand that we should, say for example, re-conductor a transmission line so that it will be less environmental impact, and so on; however, in order to re-conductor the line, you've got to take the line out of service to re-conduct it, so what are we going to do between now and when the line comes in service? And it's a fleeting opportunity that you can do that because just the load growth, you may not be able to take the line out of service very efficiently.

And then, of course, also providing information, once a project is approved, then we need to have milestones and schedules and corrective action on both sides, the developer and the transmission owner.

Incentives or penalties, well, you work with the development community to define what realistic development areas are, and then we can identify some desirable transmission areas. Well, you know, in the PPA process, in the bidding and evaluation process, the utility would have considered transmission and then still sign the PPA, so therefore it would be rather -- and then have the Resource Calculator come in and say, "Take out projects that already have signed PPAs and supposedly transmission is already being considered, and it's approved -- well, approved PPAs. So that seems to be counterproductive, so therefore the portfolio that should be needed would be the one that is the base. And I agree with San Diego, as a base that should include all projects with PPAs and then look at the other uncertainties for projects we don't know anything about.

Then, we also include mechanisms to ensure timely availability of needed infrastructure, which would be a good thing because, if your project is -- if a transmission project is in service to make a generation project deliverable, in 2018, and your generation project is coming on line in 2015, that's not going to help.

Then, also, that the information needed by stakeholders for the decision making, well, the first and foremost is what does the customer need. Does the portfolio fit for the utilities? Because if they don't need certain things, there's no point in building generation to support something with no need.

And then, of course, the value that the generation would bring to the table, that is not just energy; the value is that you need to be able to operate a system, what kind of support that a generation can provide. And then the potential environmental impacts, and then the time and cost of the transmission upgrades. And, again, I look forward to working in the stakeholder meetings with the CPUC on this new portfolio. Thank you.

MR. HESTERS: Any questions? Next, we have Tony Braun representing the California Municipal Utilities Association.

MR. BRAUN: Good morning, Commissioners. When Mark first contacted me to participate in this panel, my first question was, "Why?" As a POU community, we are a little bit outside of some of the details of what's happening here, we're certainly not involved in the scenario planning development process, although we certainly look at it when we see it translate into the

ISO's transmission planning process. We're not highly engaged, thankfully, in the LTTP at the PUC, but, again, certainly the outcome of that process impacts us as ratepayers.

For the entities in the California Balancing Authority, many of them, many of the POUs are already at 33 percent, so we really look at this as a significant cost driver, the end result of all these deliberations is a significant cost driver. When we see transmission rates go from roughly $2.00 MWH at the early part of the Century, to around $8.00 now, headed towards $18 MWH per the PUC's estimations; in a very short period of time, transmission is no longer a de minimum impact on the end bill, it's a $20.00 MWH uplift and that would have the impact of changing rates in a non-trivial manner. So that is clearly our emphasis when we examine these proceedings.

At the outset, I think it's really important to understand, and many of the presenters have emphasized this, how far we've come. And I think the sound bites of transmission as the obstacle, etc.; those are pretty stale by now. The ISO has approved, and the PUC has sited significant transmission lines for the sole purpose, basically, of delivering renewable resources. The ISO has provided its analysis that the approved projects are adequate to deliver 33 percent renewable resources. And the TPP-GIP integration that Lorenzo described earlier, we have been fighting for some time because it seemed to us to be nonsensical that the entire transmission build out was driven by an insular and opaque generator interconnection process that wasn't public, and really didn't take into account in a holistic manner the cumulative cost impact on the build out of the grid. And so TPP-GIP integration is something that we hail as a significant development.

We also believe that the development in scenarios is a significant improvement. So, you know, we're in the initial stages of that; can the process be poked at? Almost certainly. We'll do some poking, as well. But to think that we don't need to do those types of holistic efforts and, instead, just develop something on the transmission grid on a project-by-project basis, seems to be not very supportable.

So we hail the efforts by the ISO and the PUC to take a look at this in a holistic manner and think that anything but using the least cost build out to achieve 33 percent as the base scenario, before building in other factors, it's certainly difficult to understand why anyone would do something other than that.

The other broad observations I would make are,

1) I think a lot of what's going on when I hear and read comments about whether we should use the commercial scenarios vs. least cost, are driven by the fact that we've had a project-by-project approach to date, and so there's a queue, it's way bigger than the net short by many multiples, and someone's ox is going to get gored at the end of the day when we cull it out and we decide what is going forward. So, in one scenario, Party A's ox is gored, and in another scenario, Party B's ox is gored. And we've created this problem because we let the queue process and the GIP process go on so long, as it is now.

At the ISO and at FERC, we have urged that we essentially start from scratch, that we apply an economic test that the ISO is proposing to go forward to the existing queue, as the only way to really make economic and rational sense as to what is the most cost-effective way going forward. We recognize and we're highly sensitive to the commercial expectations of the parties, but, I mean, we have an unanticipated problem, and a problem that was never thought to get to this magnitude, so we need a way to decide what's the most cost-effective way to go forward and it seems to us, looking at the most cost-effective solutions in the queue is the way to go.

The other thing, particularly for Mr. Florio, it seems to us, again, sort of as the outside looking in, is that a lot of these upgrades, and therefore the transmission build out necessary, are driven by the procurement process and the value -- the RA value that is associated with these projects.  And it, at a minimum, it seems like both the RA value and the integration cost requirements need to have a fresh look.  We see scenarios where we're at 140 to 150 percent of a planning reserve margin, I'm not sure whether that's apples and oranges when you're looking at it as we have traditionally, but it does make one think, why do we need to have simultaneous deliverability of all these new resources that are being added to the grid?  And is there a way, therefore, to lower costs to consumers by devaluing to a certain extent the capacity attributes, the simultaneously delivered capacity attributes, of these resources, particularly when they're intermittent?  So I would say that a piece of the puzzle that we see, that needs to be examined going forward, and we know the PUC has plans to do so, is just what tweaks to the procurement policy need to be made to select the right resources.

So, in summary, we're highly concerned about the cost of the build out; 33 percent applies to everyone now, and we're going to pay these transmission costs, so let's keep them to the amount that is required to achieve the 33 percent build out, and achieve these energy goals in the most cost-effective manner possible. And that's our focus right now when we look at these ISO and PUC Initiatives.

COMMISSIONER PETERMAN: Tony, thank you very much. Considering you weren't sure why you're on the panel, you came up with a number of things to say, so I appreciate that. You know, we specifically wanted to have your involvement, or representation of the Public Utilities, because, 1) you represent a significant share of the State's load, as well as you have a transmission that your members also own and build. And I appreciate that your process is different, that the POU processes are different, considering that built transmission and generation model, and the consideration of both of those elements in the RFP at the same time. But I was just wondering if, you know, following the process that's happening at the ISO, if there are any other changes that you're aware of that L.A. might be considering, or other System Operators might be considering with their processes? And have you also faced the same challenges with a "rush," if you will, of requests for interconnection, considering the 33 percent goal? And feel free to respond now or in your comments, but we want to make sure that the perspective of the Public Utilities is considered as we think about this general topic of interconnection.

MR. BRAUN: So let me respond to you in an anecdotal way and follow-up with some empirical evidence. To my knowledge, we have not had a rush. I think it's driven by a couple of factors, 1) the ISO'S historic policy for this was driven through the GIP process, especially when ARRA and a whole host of other factors came into play, relieved the generators of the cost responsibility of much of the interconnection costs, including the network upgrades for deliverability. And then, going forward, the generators under the current ISO tariff don't pay wheeling charges. That is not the predominant model under a FERC pro forma, open access tariff, which is largely adopted by the significant transmission owning POUs in the state. So there's a reason why the generators would, I think, flock to the ISO's queue, in addition that they're obviously delivering debt as in PG&E and San Diego, mostly. So, let's never lose sight of the fact. So there has not been a flood, a significant queue with, however, the exception of IID, which is obviously in what has been termed the Saudi Arabia of renewable resources. They have obviously a lot of renewable potential, but they also have significant permitted rights of way and other advantages, disturbed Ag land, etc. And so they have a lot of advantages and Jaime already described, I think, some of the fairly significant numbers that are actually moving forward and in their next tranche of interconnections to their system. But as far as the Northern California public, the Federal Government, the Western Energy Power Administration, there really hasn't been to my knowledge that backlog.

CHAIRMAN WEISENMILLER: A couple questions. First, in terms of the POU Balancing Authorities, in terms of their planning, is there anything similar to the RA deliverability requirement of the PUC ISO? And if so, what is it?

MR. BRAUN: There is not what I would call the RA construct that is embedded in the tariff, and in the CPUC's rules. When it comes to the procurement rules and the 90 percent of planning reserve margin a year ahead, those rules are fairly similar, I mean, to the entities that are applicable, so some of the POUs outside the ISO are so long on capacity that, you know, and it's all owned generation, so it's kind of irrelevant to try to compare those two. But for entities that are on the market buying capacity, they have very similar procurement rules, they're guided by what comes out of that. But they are still vertically integrated utilities, and so there isn't an upfront analysis of where the generation gets interconnected on the transmission and its impact on the simultaneous flows because they wouldn't interconnect generators at an area that couldn't deliver the resources, they would look elsewhere, or they would integrate the transmission upgrades for those resources as they were moving forward with their utility owned generation plants. So there really isn't an analogous -- what I would call a highly complicated RA deliverability test because it just never would get there, I mean -- I guess maybe it's more accurate to say it's implicit in their resource choices, it's not unbundled from and a separate track analysis.

CHAIRMAN WEISENMILLER: And in terms of, do you have any sense of what the ratio of their bids is in terms of what's being bid vs. what's needed? Is it the same sort of 10:20:1, or don't you -- obviously, if you don't know, you can just say so.

MR. BRAUN: You mean as far as the bids they're receiving to meet the 33 percent?

CHAIRMAN WEISENMILLER: Yes.

MR. BRAUN: I do not know the answer to that question. To answer that, I think I would go back to the major RFPs that are out there to see what kind of solicitations they're getting. I think it's helpful in looking at that question to see how different the resource portfolios are, as compared to their IOU brethren, you know, let's say people saw the handwriting on the wall a few years ago on SB 2, and really went out in an aggressive way to try to ramp up their renewable procurement, also driven obviously by GHG reduction mandates, and so if you looked at a typical POU resource picture for renewables, you would see a lot of firmed and shaped products that were entered in before SB 2, utilizing existing transmission rights, and the physical location of those generators may be in Oregon, or Washington, or Utah, or Arizona, utilizing their existing rights on the interties to deliver those to California, a lot of utility-owned generation, wind generation, and then a host of other things, as well, close to home -- landfill, biofuel, etc., not a lot of central station solar PV requiring extensive build out, so it's a much different resource picture, and those numbers are in a lot of the data that is produced for the Commission, it would probably bear looking at, so when I get you the numbers, they'll be really responses to RFPs and things like that, but they just don't have that same analogous resource picture.

MR. HESTERS: Next, we have David Miller with the Center for Energy Efficiency and Renewable

Technologies.

MR. MILLER: Good morning. Thank you for the opportunity to address the Commission on this important topic in reaching California's Renewable Portfolio Standard. So we have some -- CEERT has some significant concerns with the way that the planning process is going forward so far and, so, thank you for the opportunity to address you guys on this.

For starters, the CAISO's TPP-GIP, the Transmission Planning Process and Generator Interconnection Procedure, formerly known as TPP-GIP and I guess it's now GIDAP, I guess we can call it "giddy up." We believe that this is actually a really good effort towards solving the generator interconnection over-subscription problem on the queue, as a lot of the former speakers on the panel have agreed. The problem that we see is that, because it really specifies, then, the way that deliverability network upgrades are assigned to resources, it becomes crucial that we have a very good and well vetted base case scenario. And unfortunately, to date, we haven't really seen significant amounts of stakeholder input into this process, and so we're grateful for this opportunity here.

One of our big concerns is around deliverability, as a number of the other panelists have mentioned, and basically our concern is that deliverability right now does not seem to be a part of the transmission scenario planning process, but it's rather applied after the fact in a somewhat arbitrary manner. And we would rather see the costs and the associated with deliverability be incorporated into the process where the scenarios are developed, in a manner that does some kind of economic optimization accounting for resource adequacy needs to the system, balanced with congestion relief, and in a manner that counts for the capacity values of variable energy resources across all hours, and not just peak.

The problem right now is that the procurement process is really focused on looking at resources that are fully deliverable, even when energy only may cost a lot of money to utility customers and still provide the same reliability to the system.

We shouldn't really be trying to design a system that manages all extreme events when simple and judicious curtailment could minimize the transmission build out we need to develop a reliable system. On the other hand, we don't want to develop a system where we excessively rely on curtailment because that's going to ruin the bankability of variable energy resource projects.

So, said another way, full deliverability may lead to a massively overbuilt transmission system at a large cost to the system, whereas the converse is that a system with too many projects that are energy-only may lead to a lot of congestion and a lot of economic curtailment, and also can reduce the bankability of variable energy resource projects.

So we really need to find something between full deliverability and energy-only and consider a manner in which projects that are being staged is considered into the overall process. So is there a common sense middle ground, and how can we incorporate that into the planning process? I guess that's one of the big questions.

Also, the Pacific Northwest is currently looking at these problems in great detail, and so we should think about how we can look to their experience to inform our own.

Okay, a couple of other comments. Why is the PUC's cost-constraint case the preferred case? It's not really clear to us why this is so. For starters, the so-called cost constraint case seems to imply that it's the lowest cost scenario, however, it's not necessarily including all system costs, including deliverability network upgrade costs. And so we'd like a better justification for why this is being chosen as the base case.

We're also really concerned that the approach that the PUC has developed doesn't really solve this so-called chicken and egg problem. What I mean by that is, if you have a region with optimal fuel source on environmentally degraded land, in an area close to load center, then we believe that those regions should really be considered as part of any system plan, and scenarios that are developed should include access to those types of regions. And we're specifically referring to Westlands and West Mojave, for example.

But right now, because those regions don't have either existing or planned transmission capacity, they're not going to be included in the commercial interest score, and therefore they're not going to show up in the CPUC's scenario planning. And we think that's a really big problem with the current approach.

We're also concerned with the lack of coordination with DRECP. As has been described, DRECP is a really forward looking view at how to use our desert resources, it actually looks out to 2050; unfortunately, the current PUC process does not use the latest vintage DRECP results, and we think that's a significant shortcoming, and so we'd like to see better coordination.

And finally, I think any scenario plan that we develop here -- that we are addressing here today -- needs to consider looking at beyond 2020 and beyond 33 percent, otherwise we may find ourselves in the same room in not so many years discussing the same things. Thank you.

COMMISSIONER FLORIO: I wondered about your comment that the PUC scenarios are not sufficiently coordinated with the DRECP, I mean, that was a lot of the work that we did this year in modifying the scenarios, as Roger Johnson talked about, was attempting to do exactly that. Did we miss the mark somehow?

MR. MILLER: My understanding that the latest DRECP results were not included.

CHAIRMAN WEISENMILLER: Roger, do you want to -- could you help clarify for us what's going on here?

MR. JOHNSON: I think what's being referred to is the refinement of those renewable energy study areas that is occurring right now in the different scenarios that are going to be developed for the alternatives. As I mentioned earlier, we believe that 90 percent of the areas that were studied in part of the LTTP process are still valid and still current. There might be some 10 percent that could be looked at again, but it's a small number.

CHAIRMAN WEISENMILLER: Yeah, I was also just going to follow-up for a second. In terms of the commercial interest case is, as I noted, the one case that includes the Kramer line, so presumably that at least addresses some of your West Mojave concerns if that were chosen.

MR. MILLER: Sure.

MR. HESTERS: Next, we have Kristin Burford with the Large-Scale Solar Association.

MS. BURFORD: Thank you very much, Chair Weisenmiller, Commissioners Peterman and Florio. I really appreciate the opportunity to be here today. I am Kristin Burford, Policy Director for the Large-Scale Solar Association.

Just to give a little bit of context about our involvement to date -- sorry, I wanted to face you guys, but that's not working out very well --

COMMISSIONER PETERMAN: You can just face straight ahead. Appreciate it, though.

MS. BURFORD: LSA has been actively engaged in the PUC's Long Term Procurement Planning Proceeding and the CAISO's Transmission Planning Process, where these scenarios were originally developed last year and subsequently used for planning. In addition, LSA has been actively involved in several other renewable planning initiatives, including the DRECP and the PEIS. We've also been involved at the CAISO in their TPP-GIP integration process and, like many of the other panelists today, we agree that that's a step in the right direction.

Generally, we're pleased to see that the CEC, PUC and CAISO are all working together and trying to coordinate these different planning efforts, this is very much a positive first step, but it is still a first step. There is significant work left to be done on these planning efforts and to ensure that the agencies are all sending clear, consistent, and appropriate policy signals across the renewables market. I think we've heard a lot from the different panelists about the need to think about not just renewables, but also to look at this process much more holistically and think about the entire system. And I think that's one of the next things that we need to see happening in this planning process.

The scenario assumptions are really critical and feed in to some of the State's fundamental planning processes, and right now we've got a pretty narrow look, I think, in terms of how we're developing those scenarios, and we do need to kind of step back and think more broadly about what that should look like.

I'm going to start with some general

observations from a stakeholder perspective, and then get into our specific concerns with the scenarios, this round that we've seen, that were presented earlier by Kevin Dudney.

I think broadly, as a stakeholder -- or these coordination efforts move forward with the agencies, we need to continually think about the timeframes that we are planning for, and what can reasonably be accomplished in those timeframes, and what information is being sought out of each of those different planning efforts.  If the goal is to send policy signals, the agencies have to consider the timing of those signals, whether those are coming at the appropriate time for the market to react, and giving the information to market participants, the developers, utilities, so that they can actually make decisions and respond to those signals in an effective way.

We have to be careful not to undermine the work and progress that has been done to date to achieve the RPS.  There's been a great deal of planning that has gone into this and we need to build on that, rather than, I think, kind of trying to erase some of the things that have been done and some of the things that have been accomplished.

When thinking about outcomes, we need to consider whether the planning efforts are the policy drivers or are policy-driven. To the extent that the planning is intended to drive policies, I think we need to think about what information is needed to inform the policy decisions that are going to be California's next steps. We're currently looking at 33 percent and now planning beyond 2020, and there is a big question as to whether or not that's appropriate, and that's going to give us the information that we need to move beyond 2020 and beyond 33 percent. I think, you know, we could look at a broader renewable goal, we could start thinking about greenhouse gases, and those goals and how we achieve those, and whether or not that's going to be changing the renewables portfolios.

And then there have been a number of other issues that have come up about what other uncertainties there are going forward. I think electric vehicle growth is one of those things, and thinking about how those might fit into the scenarios.

On the other hand, if the planning is more of an in-state, we need to ensure that these planning efforts are consistent with other implementation efforts, and as I've mentioned previously, that we're sending clear and consistent market signals from these different planning proceedings and procurement processes.

Getting to this year's scenarios specifically, I think that this actually kind of touches on kind of an interesting question. Right now, in the scenario design, two of the four scenarios are focused on cost scoring, and that's the High DG scenario and the Cost Constraint scenario, both of which weigh costs at 70 percent. And in the scenario calculator, there are really two components to cost, technology and transmission interconnection costs. Generally, a project that requires transmission is going to fare better than one that doesn't because, largely, the technology costs are largely consistent across the technology, there's not individual project costs in there. So projects that require transmission are less likely to get included in the scenarios, thus the scenarios effectively exclude projects requiring transmission. And it's not really clear whether or not that's going to be an appropriate outcome, or the policy goal we should be driving towards, or whether or not that's taking too limited a view of the broader system.

To get to the specific concerns we have this year about the scenarios, I'm going to touch on those now, but I do just want to recognize that I think many of those have already been addressed by the other panelists, so I'll try to keep these remarks relatively brief.

We, like many others, support a strong focus on Commercial Interest and using the Commercial Interest scenario as the base case scenario. In the 10-year timeframe of the TPP and LTTP, a good deal of the capacity needed has been contracted for at this point. And knowing what PPAs are out there is really a critical information source for looking at scenario development in that timeframe.

In terms of what we expect on the ground, Commercial Interest is really the data source that best distinguishes the likelihood of individual projects developing, and is tied to those projects actually materializing. I think the cost assumptions, like I said, those are more general, and they don't really give the kind of information that gets to that individual project level.

The Discounted Core has similar concerns in terms of not properly representing commercial interest. It is designed, we feel, to effectively exclude projects that have more distant on line dates due to the requirement that those projects must have a final permit to be included in the Discounted Core, and also to include projects that have transmission needs. And the scenarios presented to the CAISO, the projects were both required to have a completed PPA and completed permits to get to the Discounted Core, and for many projects that are going to be coming on line in later years, it's just not commercially reasonable to have a completed permit at this point.

And I think just based on the results that we see in terms of scenario development, the projects that require transmission were not included in many of the scenarios; the only scenario where we saw transmission was needed was the Commercial Interest scenario, the Kramer line. So if there are any projects in the Discounted Core that need that line, those projects would effectively be forced out.

And I think this other issue was touched on in the earlier presentation, which was the transmission costs associated with non-CREZ resources -- I believe, Commissioner Weisenmiller, this was your question, but I do want to at least address this briefly because this was a concern that we brought up previously -- we're very concerned about relying on incomplete data. The transmission costs for projects in the CREZ have been studied and those projects that were deemed to require new transmission were effectively penalized in the cost scoring. If we don't have information about projects in the non-CREZ area, and they're assumed to fit on existing transmission lines, and those are not assigned appropriate transmission costs, what we're doing is, I think, undermining our previous planning efforts by essentially throwing projects that we have information on, holding those to a much higher standard, and assuming that the unknowns are going to be less than the known's, and I don't know that that’s a fair assumption, or really have any reason to make that assumption. So I think disadvantaging those projects where we have information is very troubling and sends destabilizing signals to the market about how we move forward in California.

And I will just say, to this point, it's important to note that the non-CREZ resources ended up comprising about 40 percent of the proposed base case, the cost constrained scenario, which is very significant, and the non-CREZ resources at that level are likely to actually require new transmission and have additional transmission costs.

So I just want to get back to what I think is the fundamental point, in closing. And that's really we need to make sure that we're sending consistent clear signals from all the different processes, and I think right now we feel like things are moving in that direction, but we haven't quite got there, and there are some really important steps that still need to be taken in order to make sure that we do that and protect the market and make sure that enables us to reach our renewables goals. So, thank you again for the opportunity to be here today. I appreciate it. I'm happy to take any questions.

COMMISSIONER PETERMAN: Thank you very much. A question. So, looking at the scenarios under the cost constrained scenario, there is a much larger build out of large scale solar than there are under the other scenarios, specifically relative to, say, the commercial interests. And not being personally as involved in this process, my expectation is that perhaps we see that higher build out with the cost constrained reflected in the lower -- the cost declines we've seen in solar PV in the last couple years. And I was just wondering, do you see the Commercial Interest -- do you have an expectation of the Commercial Interest in solar PV increasing in the near term, catching up with these cost declines we've seen? Or do you think that the difference really does reflect the project certainty?

MS. BURFORD: So, I mean, I think there's a number of challenging questions in there. I do think that, you know, we may see some shifts in terms of where the market is going in the future based on the cost declines that we've seen. But I think we need to be careful because those cost projections are projections, and to the extent that we've got that individual project information, I think that that's going to be really critical in terms of defining what the development future looks like.

COMMISSIONER PETERMAN: Thank you.

CHAIRMAN WEISENMILLER: I guess the one thing which we really struggled with on the role of PPAs is that, obviously, no one really goes forward without a PPA, right, you know, that 10:20:1 ratio, the ones that get the PPAs are the only ones left standing at that point. But we still see generally something like a 40 percent (very '08) failure rate among the PPAs, so part of our challenge is trying to guess which of the 40 is going to -- which of the projects is really going to make it and which of those aren't going to make it, so do you have any sense on that question?

MS. BURFORD: No, that's a task I definitely don't envy you for. We do recognize that there is a project failure rate and that that should be taken into account, but I still do think that, in terms of which assumptions might get us to the most likely future, the PPAs, as you mentioned, are really the source to show which resources have the best likelihood of being developed. And in that respect, that needs to serve sort of as the basis of these planning efforts. I think, you know, with further stakeholder process, that that should help in terms of helping to figure out how we take into account contract failure, but at this point, I don't have a specific suggestion.

CHAIRMAN WEISENMILLER: And the other question, which we struggled with, is that obviously Roger was dealing with lots of projects going through that, and then trying to make sure that the characteristics of the projects are actually reflected in the model, as opposed to -- obviously there's a lot of stuff to move fairly quickly, and so trying to check on how much chance people had to go through and vet the underlying data, so that we're not really disadvantaging any projects through mistakes.

MS. BURFORD: Yeah, I think that's actually a very important point. I know a number of our members have reviewed the data and found that there were some errors, I think, just some out of date information in terms of how their projects were represented in the different scenarios. So it is important when you're using this process to develop these scenarios to ensure that we've got some time for stakeholders to get into that source data and make sure that projects are accurately represented. And to the extent that we can make sure that we have that opportunity upfront, the stakeholder process so far has been relatively rushed and I think stakeholders were kind of scrambling in terms of trying to figure out how to do that. But if we've got that data developed at an early state, even before we develop the scenarios, allowing developers to review that data at that point could help ensure that we solve some of those problems.

CHAIRMAN WEISENMILLER: Well, certainly if there are any obvious mistakes, if you could put that in our record and in the PUC record, and obviously the intent is to try to have the best data available at this stage.

MS. BURFORD: And I can check if we can do that. I know that some of our developers actually decided to file individual comments on those issues, and some of this is very commercially sensitive --

CHAIRMAN WEISENMILLER: Sure.

MS. BURFORD: -- so I don't know how public all that information is, but to the extent that we can, I will check with our members.

CHAIRMAN WEISENMILLER: Okay.

COMMISSIONER FLORIO: I believe that the data is being updated to capture those known errors, and you know, I think the fact that the scenario development process is already starting for next year is an indication that we've learned from the past and are going to try to do it better. This year was rushed for everyone and, partly, that's because it was an off year for LTTP, but I think we're going to try to regularize this process going forward so it's not such a rocky road for everyone.

MS. BURFORD: Thank you and we definitely appreciated that. I think, you know, one of our concerns was essentially the first time we got to see the new scenarios and the updates was over at the CAISO, after the Commissioners had had the opportunity to sign off on those, so it would really help to get some stakeholder input, I think, upfront in the process, before that happens, just so we can make sure that we get it right in as early as we can.

COMMISSIONER FLORIO: We agree.

CHAIRMAN WEISENMILLER: Yeah, we agree, although I think our hope was always, obviously, the timing was pretty rushed, but that to the extent people have comments on obvious mistakes or errors, that we get a chance to reflect those going forward.

MS. BURFORD: Absolutely.

MR. HESTERS: Next, we have Chris Ellison with Pathfinder/Zephyr, they're both LLCs.

MR. ELLISON: Thank you. Can you hear me?

Chris Ellison, Ellison, Schneider & Harris, on behalf of Pathfinder/Zephyr, and thank you for the opportunity to appear before you today. First, who is Pathfinder/Zephyr? Pathfinder is a proposed 3,000 megawatt wind project in Wyoming. Zephyr is the Direct Current transmission line, dedicated transmission line, now owned by Duke American Transmission Company, that is proposed to transmit that power to the El Dorado Valley and the California ISO. This is an ambitious project, it not only includes what I've already described, but it includes setting aside land in Wyoming currently owned by the Pathfinder Ranch and others, that is some of the most environmentally valuable land in the United States, that has been compared in geographic size to the size of Yellowstone National Park, I'm not sure whether that's exactly correct, but that gives you some sense of the scale. It has 35 miles of flat riverfront, and it's an extraordinary environmentally beneficial and ambitious proposal, along with the wind development and the transmission line that we're talking about.

Pathfinder/Zephyr also believe, because of the wind resource that exists in Wyoming, because of some other factors, that it can offer very competitively priced renewable energy to California, and the question is will it have the opportunity to demonstrate that.

That being said, let me say first of all, that one of Pathfinder/Zephyr's main comments was the concern that you've heard, I think, from everybody about the need for more stakeholder input into the scenario planning. And this collaborative effort and the presence of all three of you here is certainly a major step in that direction, and I want to acknowledge that and express our appreciation for being included in that.

What I want to do now is I want to say first that I agree with the vast majority of the comments that you've heard from the previous panelists. I think there's definitely a consensus around certain kinds of questions, and I’m not going to repeat all that, I would be happy to take questions on any specific aspect of it, but I do agree with the majority what you've heard.

I want to touch on two or three very specific things, and then I want to step back, we've been hearing a lot today about a holistic approach about how we deal with uncertainty, about the chicken and egg problem. I do have some thoughts on that, and I want to spend a few moments talking about that.

So first, the first specific comment is I do want to remind everybody, and this is in part, Commissioner Florio, in response to your question about cost and the risk of stranded investment, and over-planning and over-building. I do want to remind everybody that it remains Federal law and it remains the policy of the ISO fundamentally that the generator pays for all of the interconnection costs, and finances all of the network upgrade costs, and gets a return of the finance network upgrade costs when they come on line. If they do not come on line, they do not get any return on that. So fundamentally, there are some exceptions, but fundamentally the risk -- the financial risk -- of, if you will, over-planning, and even over-building, is born by the generators and not the ratepayers, that's a very important thing, I think, to keep in mind.

The second key thing that I would want to emphasize is that we have a rather large disparity in the precision of this process, we have a great deal of information about, for example, in the environmental scenario about the DRECP, and the projects in that area. For projects like Pathfinder, however, that are out of state, there's this very crude simplifying assumption that it gets an environmental score of 50 as being neutral. That's wildly simplistic.

The third point is that, and this is again a point about the opportunity for stakeholder input, you know, the updating that has occurred from our perspective looks quite inconsistent. The costs of PV were lowered by 30 percent, but there's been a similar change in the cost of wind power, and specifically the wind power assumptions in the 2010 scenario were based upon -- for out of state wind -- were based upon the Western Governors Association's CREZ planning effort and the cost of wind power, for example, in Wyoming that was used in that effort. That assumption was not updated, even though the Western Governors Association issued a report in 2012 that does update and significantly lower those costs. So consistency in the updating is a concern that Pathfinder and Zephyr have.

There are also some concerns about double-counting, imposing the costs of transmission on those projects that need transmission, and at the same time crediting, for example, Distributed Generation with the fact that it doesn't need transmission. That has certainly been raised by Pathfinder, Zephyr, and many other stakeholders as sort of double-counting.

But with those specific comments, let me back up and close with the broader philosophical concern that I certainly have, and my client certainly has, and that goes to this whole question of how we reform the process, how we deal with uncertainty, how we deal with the chicken and egg problem and all of that. It goes, for example, Chairman Weisenmiller, to your question about how do we know which projects are going to make it and not make it among those that have PPAs. And it goes fundamentally to this question that is posed to the panel about uncertainty. Let me begin with five facts that I think are not uncertain, and I think these are things we can rely upon; the first is that transmission is the key barrier to entry for generation; if you don't have transmission, you don't get there. That remains true. And it's particularly true for renewables that don't have the same kind of flexibility in choosing a location that non-renewable projects have.

The second, I think, key fact is that it's the cost and the environmental impact of California's entire electric system that counts, not just the transmission component. The transmission component, as PG&E pointed out, and I agree with, even though the costs have gone up, as Mr. Braun pointed out, are still a relatively small portion of the total customer bill and they are also a relatively small portion of the environmental impact of providing electricity in California. Transmission lines don't have emissions, they don't use much water, the impact is fundamentally visual, they're difficult to permit and we all know that, but the environmental impact of transmission is relatively small compared to generation. That notwithstanding, it's important to keep in mind, and this is probably the key fact, that transmission is in many ways the driver of the generation of the environmental impacts and the generation costs; as I started out by saying, transmission is the key barrier to entry.  And so, even though transmission itself is a relatively small component, it is a key to which generation gets built and a key to the environmental impacts and the costs of the generation.

The next fact is that transmission's long lead time is due primarily to planning and permitting, not construction.  You can build transmission pretty quickly once it's authorized to go forward, but the planning and permitting can take many many months, we've seen estimates of 72 months to bring something on line, where less than two years of that is the construction for major transmission in California.

And the last fact that I would put in front of you is, I think, the most important one of all, and that is that we don't know the future.  We don't know which projects are going to make it.  Nobody's crystal ball is particularly good.  We wouldn't have necessarily anticipated what's going on with San Onofre and the importance of Sunrise.  We don't know necessarily, we wouldn't have necessarily predicted, a 30 percent drop in

PV. A lot of these renewable resources that we're talking about are undergoing very rapid development and very rapid change, nobody's crystal ball is very good. And it's that that I want to really emphasize because, given that, I think the right way to deal with transmission is to, first of all, separate the authorization for planning and permitting vs. from the authorization to construct, and to some extent, the PUC already does that. But with respect to how much transmission should you plan for and permit for, given the uncertainty in generation, given the fact that transmission can drive competition, or restrict competition, I think what is prudent planning is very much the same kind of thing you would do with your retirement portfolio, you want to plan for a diversity of scenarios, you want to hedge uncertainty. And so what I think -- and this may be a comment more for the ISO -- but I think what the right thing to do is not pick one scenario that may be the one you'd like to see happen the most, and then bet everything in terms of transmission on that, and, in particular let me say, if that scenario is the one that requires the least transmission, you really are betting because, if you plan for too much transmission, you permit too much transmission, that's relatively easily remedied, but if you don't plan for enough and you don't permit enough, that's not easily remedied. And so what I think makes sense, and what I would recommend on behalf personally, but also on behalf of Pathfinder/Zephyr, is that as we go forward and think about this, that we plan and permit, at least, for a range of scenarios, a range of generation outcomes. And then, as the future becomes more and more clear as to what scenarios are actually development, and what their costs really are, you can make construction decisions based on a much clearer crystal ball than we have now, and result in a scenario which -- and this is the key point that I'll end with -- result in a scenario which reduces the environmental impacts and the cost of the total electric system much more effectively than trying to bet on some scenario now and count on being right because, in my experience in 30 years of working in energy, and we have some of the smartest people I know in this room, nonetheless, we've been wrong a lot of times.

CHAIRMAN WEISENMILLER: Yeah. Actually, I was going to say we have at least one person on the line, so let me see if Mike -- do you have any follow-up with Chris? Okay, so I believe the Navy is on the line and I was going to offer them the opportunity to say a few words about the Department of Defense plans.

MS. KOROSEC: Do we know the name of the person who is on the line from the Navy? Vernon Hunt? All right, Vernon. Go ahead.

MR. HUNT: Okay. Can you guys hear me okay?

MS. KOROSEC: Yeah.

MR. HUNT: All right. Thank you all again for the opportunity to make some remarks in support of the IEPR. I appreciate the opportunity to talk about interconnection and transmission issues as part of this panel.

Again, as probably most of you know, the Navy has fairly aggressive renewable energy goals to pursue at least 50 percent alternative energy for our shore infrastructure by 2020, in support of that overarching goal from Secretary Mabus, Secretary Pfannenstiel has piloted her Smart Power Partnership Initiative, and Secretary Mabus has also pushed forward the 1 gigawatt initiative to move us towards those renewable energy targets and goals. As such, especially in our desert regions, our installations have some great opportunities for support of renewable energy and a lot of -- there's available land and there's available resource for us to utilize.

As has been stated kind of throughout the panel, there's lots of restrictions and issues keeping us from fully realizing some of those opportunities, particularly the transmission constraint; that's been mentioned all morning. But to get to some specifics, the SERDP study identified over 5,000 acres, appears to be compatible with existing land use constraints, and available for potential development of solar in some of our installations. And, again, until we can get the adequate transmission infrastructure to places like China Lake and others, then the ability to harvest and develop that resource, both for the Navy's consumption, but also for the general grid to utilize, we can't fully realize those resources.

The other issue that comes up when we start to talk about interconnection from a Navy perspective is we've been working on lots of distributed generation across our installation, so we've got lots of rooftop solar, we've got lots of carports, we've got lots of variety of renewable energy sources on each installation, and as we approach interconnection of large systems, one of our major concern is backwards telemetry, if that makes sense. So the idea of having to go back and retroactively provide advance telemetry on these smaller installations, that in some cases have been there for years, in order to support the development of larger solar projects on our installations. And, really, that's a Rule 21 interconnection issue and not a transmission issue, sorry. So in either case, there's several opportunities that we have. As the Department of the Navy, we do have land, we do have land located in prime resource areas, both for Navy consumption and for export onto the grid, and without some relief with some of the transmission constraints, and the Rule 21 interconnection issues, then it will be difficult for us to move forward in developing that resource fully to support the goals of both the State and our Secretary on the Federal level.

Again, we're looking forward to continue partnerships with the CEC, with the utility companies, with the PUC and ISO as we move forward in pursuing these renewable energy goals, and we thank you again for the opportunity for us to kind of present our perspective on these issues through this series of workshops.

CHAIRMAN WEISENMILLER: Thank you. Questions?

COMMISSIONER FLORIO: Just a comment. This is Mike Florio from the PUC. You may know that we're currently -- we have an ongoing proceeding dealing with reform of Rule 21 and we would very much welcome your participation in that process so that we can hopefully address the problems you're confronting. So you're more than welcome to participate there and give us your issues and concerns.

MR. HUNT: I appreciate the invitation. We actually -- you guys have extended that previously and we have a representative from the Navy that is serving on that task force, Norm Furuta, who works out of our San Francisco office, so he's very actively engaged in making sure that our issues are put forth and are part of the dialogue and discussion.

COMMISSIONER FLORIO: Excellent.

CHAIRMAN WEISENMILLER: Great. Thank you. I had asked a question to IID's representative and she's not the right person, is it possible that Bill Kissinger is on the line? He might be able to answer that question. It's also possible he's not.

MS. KOROSEC: I'm sorry, what was the name?

CHAIRMAN WEISENMILLER: Kissinger, Bill Kissinger. While you're checking, I was just going to make the observation, not to provoke a dialogue among the panel, but just in our last workshop Commissioner Peterman and I both observed that one of the issues pending in this IEPR was whether to increase the renewable standard above 33 percent, and obviously the Governor has said that's a floor and not a ceiling, but certainly we welcome comments from all the participants in this IEPR on that notion.

MS. KOROSEC: Mr. Kissinger is not on the line.

CHAIRMAN WEISENMILLER: Okay, great. So do you want to go back to public comment?

MR. HESTERS: Yes, we're going to open this up to comments from stakeholders in the room. I have a blue card from Pushkar Wagle from Flynn RCI.

MR. WAGLE: Thank you for the opportunity to speak here. I'm Pushkar Wagle from Flynn Resource Consultants. We represent interests of Bay Area Municipal Utilities. And I have two broad comments in the area of TPP-GIP integration, as well as -- and the second is the resource portfolio. And Dr. Kristov here clearly articulated about the GIDAP process and that initiative is applicable to Cluster 5 owners, so there are still about 40,000 megawatts of renewables in the existing queue. It was a decline from about 55,000 in October of last year, so today it is about 40,000. The ISO footprint needs about 11,000 to 13,000 MW to meet the State's goal. So we are clearly concerned that the efforts by the ISO, that are very well intended efforts that are identified in the Technical Bulletins that Dr. Kristov mentioned this morning, those efforts will likely fall short and one needs to remember that the ISO's existing tariff -- they have to interconnect those generators, they're not subject to economic tests that would come from GIDAP, so no matter what, they have to interconnect, so there is tremendous potential for some unneeded transmission in that area. So the key issue is the question Commissioner Weisenmiller asked about the deliverability assessment process. So, we have seen that this Resource Adequacy Mechanism criteria to determine the deliverability creates the need for excessive transmission, and that this Deliverability Assessment, which is a process called a DAP, that clearly needs to be reformed. It assumes stringent Category C, common outages under one in five load conditions, which are pretty extreme. Those outages can occur one in 10 years, a probability of that is extremely low. And it creates an inconsistency between the renewable generator dispatch and the RA capacity credit. For instance, wind generation gets a capacity credit for 10 percent of its capacity, however, in the deliverability assessment process, it's more or less 20 percent exceedance, which is about 50-60 MW. So why would you make such unrealistic assumptions? And mind you, this is not a Reliability Assessment, this is a Deliverability Assessment. So why make certain assumptions that are more suitable for Reliability Assessment? And, you know, in Reliability Assessment, you consider sort of lower costs and other appropriate solutions such as condition management or use special protection schemes, or load shedding, which is not done in Deliverability Assessment at all. And this contracting capacity from third-party or market is basically significantly less costly than building these Delivery Network Upgrades that come out of this Deliverability Assessment, we made some back of the envelope calculations which indicate that -- about this cost of building new upgrades -- about two and a half, or in some wind cases 16 times as high as if you just contracted third-party capacity. So I think one needs to do some sort of analysis with the rates, user, production costs, tools, or whatever, to make some realistic assessment in terms of how much -- what's the tradeoff between building all these unneeded renewables vs. contracting the possibilities for third-party. So, as CEERT mentioned earlier, you really have to strike the right balance between how much curtailment is okay. And this, we are talking about curtailment, we are not talking about load shedding here. We are not talking about reliability issues, well, it gets curtailed for five or 10 hours in a year, big deal. Quantify how much it's going to cost you, rather than coming up with this really unneeded and unrealistic level of transmission.

The second point --

CHAIRMAN WEISENMILLER: Okay, could you wrap it up? You get three minutes, max.

MR. WAGLE: Sure, sorry. I will take about 15 more seconds. Nobody talked about the net short assumptions that went into the portfolios, and I was shocked to see that the net short assumptions actually required remain almost the same. And then I looked into the uncommitted energy efficiency amounts, and the CHP amounts are considerably lower than the CEC staff's estimates. Incremental CHP is assumed to be zero. This is not clearly consistent with Governor Brown's goal of having 6,500 megawatts in the next 20 years. So, clearly, that number is significantly lower. The big bold initiative number says zero, as far as uncommitted energy is concerned. So that needs to be looked at. I think CEC staff is the most competent authority on these elements, and these numbers, in the net short calculations are not consistent with what came out of the latest CEC staff reports.

CHAIRMAN WEISENMILLER: Okay, thank you very much.

MR. WAGLE: Thank you.

CHAIRMAN WEISENMILLER: We had the usual challenge between, on the one hand, encouraging public comment, on the other hand, trying to give the panelists a chance to talk among themselves. So I have a list of other blue cards, but what I'm going to do is, most of these people seem to be in the room, so I'm going to hold you until later and encourage some conversation among the panelists.

So why don't we go around to each of the panelists and give you -- we're going to try to close in about 10 or 15 minutes, give each of you about a minute or a minute and a half for sort of further reflections. Carl.

MR. SILSBEE: Well, I was heartened by the degree to which many of the panelists supported the Commercial Interest scenario. I realize that is a projection of the status quo and that you may not want to see a projection of the status quo, but I think in terms of the planning process, it is a good place for us to start and, so, I would encourage you to take those comments to heart as we move forward.

MR. YAN: I guess maybe just one or two more points to add after hearing the other panelists. So, one of the things that I mentioned in supporting the Commercial Interest scenario is that it reflects the ongoing commercial interests. But as some of the other panelists talked about, particularly Mr. Ellison, it seems that we want to make sure we have optionality open for future procurement needs and, if we stick to a transmission planning process that is using cost constrained and it really seems like, from the get go, is trying to prevent new transmission from being identified, we might be looking at the wrong solutions to meeting our longer term goals.

One other thing I wanted to add in response to some of the folks who are concerned about the deliverability being something that really drives our procurement process, at least recently, and we think perhaps going forward, we think that there is room for energy-only projects, too, to actually win in our solicitations, at least to be competitive. So, I just wanted to throw that out there. Thanks.

MR. SPEER: Yeah, so I think we also need to consider implication costs of being wrong. Lower than expected low growth scenarios rarely provide as much or any useful information to long term transmission planning needs, these high/low cases. And we also need to stay away from assuming needs. Needs should be developed by looking at what we have vs. what we need. Don't assume lots of DG before determining need. And then build what is learned in the transmission planning process. And I think the procurement process, at least for the utilities, really gives us direction on what the base case would be in the future, so we need -- a commercial model is probably our best example.

MS. ASBURY: As the person that IID who manages the queue process, I hate to say I'm happy to know that other transmission providers experience the same types of issues that we do, I'm sorry that we're sharing the pain, but…. IID is committed to seeing its renewables developed. We want to continue to cooperate as much as we can with interconnected utilities and with the ISO. We have, as Tony mentioned earlier, a FERC pro forma tariff process, but we've done some things with ours where we posted stakeholder notices. And one of the things that we did identify is commercial viability. Those projects with PPAs, we have allowed to be accelerated through the process because that's the main driver, that's the sort of missing piece, if you will. You can achieve all of the other things through interconnection, but that's the one that not everybody has the opportunity to obtain. So, as much as I hate to say I feel affinity because it's not positive, I do, and again, IID will continue to share information in an effort to assist in the planning process.

MS. THOMAS: Yes, I would encourage that it's all well and good that we are planning for 2020 and beyond, and the 33 percent, and thinking about that, but a more pressing issue is what are we going to do now. And given the fact that a lot of the ITCs are coming to a close in 2016, and projects that cannot come on line by that date will have tremendous issues, and so therefore, what we really need to do is to make sure that we put in enough information for this year's planning cycle because, if we're going to wait until next year's planning cycle, it's going to be another two years before the project would be approved or not. And so uncertainty, of course, we need to be looking at the long term and everything else; however, we also need to be figuring how we're going to get there from here.

CHAIRMAN WEISENMILLER: Thank you. Tony.

MR. BRAUN: I would echo what Chifong just said, that it's nice to talk about some of these things that are far out into the future and we need to assess and plan and do multiple scenarios, but right now the ISO has a queue that is multiples of what is needed for what is the current statutory requirement, and if we don't come up with a rational way to solve that problem, we're going to spend many billions of dollars -- each of those dollars counts towards consumers' rates, and when I see my utilities with 25 to 100 percent rate increases over the course of the next decade or two projected, it's concerning and it's something to be taken very seriously.

MR. MILLER: Hi. Yeah, I agree there's a lot of need to balance the need to look forward beyond 2020 and beyond 33 percent, and also how can we address the issues right now before us. And I think one thing that's clear is that deliverability is not being addressed in a way that's going to build a transmission system at least cost right now. If we continue on the path we're on right now, we may end up over-building our transmission system and not providing any more reliability, or any more services, or any more ability to manage greater quantities of renewable resources. I would also like just to say that moving beyond 33 percent is a great idea.

I think it's also important to coordinate with other balancing areas. There are issues of compliance with Order 1000, and there's issues of how can we design a system that optimally integrates different resources and different resource characteristics; if we do pull in, say, wind from Wyoming, that could actually lower integration costs for California, so I think there's a place for that in the equation here, as well. Oh, yeah, and just one more comment, I think, yeah, the comment that a previous panelist made about how we need to consider the long timeline for transmission planning, I think that's crucial.

MS. BURFORD: So, I agree with a lot of the points that have been made so far. I think that there's two kind of competing goals here, and one of those is thinking about sort of the near term goal of 33 percent, and making sure that we plan to get there, and that we ensure that we made a clear path to achieve that goal. And we've heard a number of suggestions about how to do that, but I also just want add that we need to ensure that the transmission that's needed in the transmission planning process proceeds efficiently and appropriately through the permitting and development.

And then the second goal is, you know, thinking more broadly about what happens beyond 33 percent and what are the next steps, and what are the information -- the missing information pieces that we can get from these planning efforts that will help us inform how to move forward beyond 33 percent because I think one of the reasons why we're here today is, you know, planning is really critical, and we need to keep thinking one step ahead to make sure that the next step we can reach in an efficient and effective way.

In terms of the Cost Constrained scenario and the Commercial Interest scenario, we've heard a lot about that, but I just want to emphasize that one of the other things that's not really taken into account in the Cost Constrained scenario is sort of supply/demand limitations in terms of land, and if we are transmission constrained, those costs might actually be more than we're projecting.

And then, last, I'd just like to emphasize that I think getting the right signals in the procurement process, I think some of these things are stemming from the fact that we need to update some of the signals that are coming through the procurement process in selecting projects.

MR. ELLISON: As a provider of renewable energy, I'm sure without checking I can tell you that my client would support going beyond 33 percent. Two clarifications, just to make sure that what I said earlier is understood in the right context. When I said that transmission comprises the small portion of the customer's bill, I wasn't saying that that small portion doesn't count, but what I was saying was, if you save one dollar on transmission, but the result of that same decision is to cost you $5.00 in generation, you've spent $4.00. And that's -- it's the relationship between transmission decisions driving generation that is the key to what I was trying to explain earlier.

And lastly, if you do have to pick one scenario, the Commercial Interest scenario is the one that my client would support.

CHAIRMAN WEISENMILLER: Okay, so at this point, again, let's -- is there any public comment from someone who is not going to be here, who is on the phone or not going to be here this afternoon? Arthur.

MR. HAUBENSTOCK: Chair Weisenmiller, Commissioner Florio, just two quick points in regard to some of the questions that you raised. Following up on Chris Ellison's point regarding the costs, you know, what we've heard in public, from major PV manufacturers, for example, is that large-scale solar is actually much less expensive than some of the distributed. So one of our great concerns with the Cost Constrained case is that it may not provide what we think ultimately should be the policy goal of what we're doing here, which is to provide a least cost, least emissions grid. But regarding the DRECP, which I know there are some questions about that, currently there are six scenarios that are being looked at by the DRECP, only one of which actually reflects commercial interests, the rest of which are driven by the idea of avoiding the potential for conflict -- not actually avoiding conflict, but avoiding the potential for conflict. The Renewable Energy Study areas that were looked at as part of the process here were really preliminary and largely driven by biology, again, not reflecting commercial interests. And that's our concern, again, with transmission planning, is that transmission planning, if it doesn't actually reflect commercial interests, may end up with a policy failure, which is something that we're very concerned about. Then, also, it brings up the other question that you asked with regard to PPA failure. One of the great advantages of renewable energy is that, although companies may fail; the sun and the wind and the geothermal resources will not. What we're seeing is that, even with companies that have gone under, unfortunately, in this space there's tremendous interest in the areas that they were interested in developing and in the transmission interconnection that those resources may have had, so the likelihood, if you have a good renewable energy resource, is that resource will not be left unused. That's specifically important when it comes to renewable energy resources because of the need for diversity. If, as part of our transmission planning process, we don't learn the lessons from areas such as Texas, which had great concentrations of resources to try to avoid transmission costs, but then ended up with failures when wind would go out in those particular areas, with potential system emergencies, again, we've come up with a policy failure which can be avoided by having appropriate transmission that is built out for the long term.

What we found in working with a lot of environmental stakeholders is that they're interested in ensuring that, when we build transmission, we're building for the long term, we're not going out and building something now and then having to go out and build something later. So in terms of investment that we're making for the future, for 33 percent and beyond, being more expensive and following where the commercial interest is, again, like the economist who says that if the $20 bill was out there, it would be picked up a long time ago; with renewable resources there and the transmission is built, you can be sure it will be picked up. Thank you.

CHAIRMAN WEISENMILLER: Thank you. Suzanne, anyone else? On the line?

MS. KOROSEC: No, we have no one on the line and I don't believe there's anyone else -- oh, excuse me.

CHAIRMAN WEISENMILLER: Again, if you're not going to be here this afternoon, happy to have it, otherwise --

MR. SMITH: Thank you. My name is David Smith with Transwest Express. And thank you for the time, I'm planning -- I'm not going to be here this afternoon. I had a couple comments to make, one is on the policy goals. I think that one of the most important policy goals that was touched on by this group, but I think needs to be stressed more in the way that data is developed in this process, and everything else, is the cost to consumers, the total cost to consumers. I think that the policies that we're talking about, whether it's cost constrained or commercial constrained, all, you know, that needs to be reflected on is what is the cost to consumers. In the data that was provided by the CPUC in the scenarios, it wasn't a total cost for the different scenarios. We did some calculations and we saw a significant difference between the costs of those different scenarios, and I was interested to hear the gentleman from SCE say that they looked at it a couple years ago and didn't really see any difference in cost. The costs that we saw when we totaled those up was significantly different, and those are very important policies and decisions to make.

In addition, too, a major goal of costs and the transparency around those, is the optionality issue. Again, we need to have different strategies, not just scenarios. The scenarios presented by the CPUC were, if we wait this more, or if we wait this aspect more, or this aspect more, you know, we'll go with these different routes. Those aren't really actionable -- actionable strategies. We should wait what we feel it is important right now. I would submit to you that, if everything was turned into some kind of dollar impact in some way, that would probably be the best way to look at that.

This kind of analysis is not uncommon in the industry, it's been done for a number of years -- long term integrated resource planning, where risk analysis is looked at. It's a little bit more complicated when you have a large market system to work on, and what those different transactions might be and bidding processes, but as the previous commenter just said, the resources are the resources, there's gray areas with potential, we pretty much have a good understanding on the technology, some technologies are maturing, might be lowering costs, but there's a number of certainties that we do have and the transmission planning in a long term analysis should be focused on those certainties, and not really as focused on what might be uncertain.

My last comment is on the subject here of transmission planning and the interconnection process, generator interconnection process. I think it's excellent that folks are working on trying to move away from the generation interconnection process, to be the way to have ratepayers on the hook to pay for transmission, it wasn't really obligated to do that, I think that's party why POUs don't see the same kind of problem. At the same time, I want to caution that what is focused on this GIP and TPP, the result of that on the TPP side is not the total sum of what transmission planning should be, it's not just integrating with the GIP process, the interconnection process. You know, essentially the interconnection process was developed to connect resources to a system that was already loaded up -- or, I'm sorry -- that had excess capacity. It wasn't a way to look at transmission expansion. And so there's different ways that transmission expansion analysis can be done, again, is least cost, long term integrated resource planning efforts that could be applied, and take a look at different options for California to lower the rates. Thank you.

CHAIRMAN WEISENMILLER: Okay. Thanks. Certainly, again, remind people that written comments can be provided following up from the workshop, Suzanne, I'm sure, at the end will sort of summarize that date. I think in terms of thinking about uncertainty and how to better reflect those in the scenarios will be useful. I think we were certainly striving this time to have more divergence across cases, so whether we succeeded or not is an open question, but at least the intent was not to have four scenarios that turned out to have remarkable similar consequences at the end. But anyway, but these are all sort of works in progress as we go forward. So, again, written comments will be helpful on uncertainty. And we're going to start up again at 1:30.

(Recess at 12:35 p.m.)

(Reconvene at 1:33 p.m.)

MS. KOROSEC: All right. We're going to get started up with our second panel, our moderator is Linda Kelly. Linda, do you want to introduce the speakers?

MS. KELLY: Good afternoon.

COMMISSIONER PETERMAN: Good afternoon, I'll just -- excuse me, Linda, for interrupting. I just want to say welcome to the panelists for the second panel and we had a good first half of the day. And I've been joined for this workshop on the dais by Chair Weisenmiller and Commissioner Florio of the PUC, they will be joining us again, but we're going to start now anyway to make sure we stay on schedule. Thanks.

MS. KELLY: Just a few remarks to open up this panel. I think everybody knows that the distribution system was designed for one-way power and from customer to the generator, the central station generator. But over the past few years, because of the RPS, utilities have been adapting and integrating DG, even though the system was designed this way. But one of the key issues is that they can continue to adapt, but eventually every circuit and every substation can reach a limit, and then there will be the need for upgrades or new infrastructure. So there is a limit to what can be done with the existing system.

There are also a lot of maps and studies that have been done that provide lots of information about good circuits and good rooftops, but even these reports acknowledge that there are significant unknowns, and with regard to environmental cost, with regard to upgrades, there still is a lot of uncertainty and risk associated with identifying good spots.

During the panel today, presentations will suggest that progress has been made, but there still is a lack of experience on the utilities part of integrating this DG. And so, as a result, the utilities want to go careful and slow, they've got to maintain the stability of their systems, but on the other hand, you have developers who have business models that, really, a two to three or four-year interconnection process is just not going to support those business models for the developers.

During the panel today presentations, I think, will focus on what it's going to take to improve the interconnection process, I think you're going to see utilities are going to say, "We're doing a lot of things, we're hiring new people, we're getting smarter about what we're doing," and I think that's really important. But I think what we'll also hear from the panel is that some of the screens and some of the ways that the utility deals with these interconnection procedures need to be updated. And one of the presenters, NREL, will talk about these screens and how, as the utilities get more experience, and really get more experience with DG and see how they interact on their system, the time has come to probably look at those screens and evaluate updating them so that this process and the fast track process can move along more quickly.

And finally, we have Silverado Power, and they have a perspective, as well, and they're a developer, and they are involved in doing this business every day. And I think one of the comments that I took from their presentation is we tend to generalize about these good spots, and these sweet spots, but I think there are good spots and sweet spots, but I think there are also other spots, and one of the comments on their presentation is, just because there are a need for infrastructure upgrades doesn't mean that is no longer a good project because you're going to run out of all the great spots, and then you have to look at what other projects or what other spaces really provide benefits, as well? So that's just an overview of distribution and some of the issues that interconnection of DG is creating for the utilities and developers.

And so I'll just go forward with the first panel. The first member of our panel, which is Rachel Peterson. And I'm going to introduce Rachel, and maybe if you can introduce yourself as you go down, that might be the easiest.

I've been working with Rachel for probably more than six months, the settlement has been going on for six months, but the CPUC began thinking about the settlement about probably three months before that. And Rachel has been in these meetings, facilitating, cajoling, working with these people, she's done a phenomenal job. And she's here today to brief you on the results of the settlement and looking forward to the OYR at the CPUC that is looking at interconnection. Rachel.

MS. PETERSON: Thank you, Linda. My name is Rachel Peterson. I work in the Energy Division at the CPUC, and I want to thank the Energy Commission for the opportunity to make some remarks today about the Rule 21 Settlement and the context of interconnection in California.

And I really do want to start with a thank you to Linda and to Commissioners Weisenmiller and Peterman. You provided a technical assistance grant in August-September of last year that ended up bringing some technical expertise into the settlement process that was quite invaluable to our discussions, and they aided both CPUC staff and the settlement parties, as well. I really want to extend my gratitude for that.

So first off, I just wanted to start by distinguishing between procurement and interconnection, and I think the panelists in the last panel before lunch did a good job in identifying some of the key differences. Really, the role of an Interconnection Tariff is to serve distributed generation procurement. When you're thinking about procurement, or you're thinking about interconnection, you're really thinking about and designing two different things. Within procurement, you are asking questions about an overall program, megawatt targets statewide, what types of resources you're looking for, perhaps an individual project size cap, eligible generating technologies and, very importantly, a pricing methodology.

An Interconnection Tariff really is neutral about many of those things. It is intended to set the technical standards for a parallel operation of generating facilities with the distribution system so that safety and reliability are not compromised. A tariff must comply with whatever CPUC or FERC standards exist, but it's neutral as to size, resource type, generating technology, and pricing.

Ideally, it will set engineering analysis tracks that group generating facilities such that a utility can process them, or study them as the case may be, in the most efficient manner possible. And it also should set out what I have called Rules of Communication, which are essentially about how long does each party have to accomplish a task and respond to the other.

Now, in saying that interconnection should serve procurement, you know, it kind of follows and may seem obvious, but I'll say it anyway, that the success of distributed generation relies on the success of interconnection. And I know that many people in this room are very familiar with success and absence of success in terms of interconnection. So what I've prepared on this slide, and I'm really talking about distributed generation at the distribution system, I'm not -- I'm specifically avoiding speaking about transmission level programs or interconnection at this point.

So I've listed the major distributed generation programs along with their rough timeframe of when they started. And I have colored in the boxes with approximations of what I would term success and non-success. And as you can see -- you can find an additional list of the distributed generation programs of the CPUC in the handout that I prepared, that I think is out on the front table. And so, for some programs such as the Self-Generation Incentive Program, and California Solar Incentive, we have interconnected facilities numbering in the tens of thousands, and over 100,000 for the CSI program. The feed-in tariff, the renewable feed-in tariff, is the major program that has not seen a lot of interconnection success, and I think today we'll be getting into some of the reasons why.

Now, I also just wanted to spend a moment speaking about the applicability of the different tariffs. Interconnection is confusing and complex in California in part because we have three different tariffs that apply to the electric system, the first two on the distribution system are Rule 21 and the Wholesale Distribution Tariff, or the Wholesale Distribution Access Tariff, commonly pronounced "Widdit" or WDAT. And they have different applicability because of jurisdictional and legal rules about where they are to apply.

So just starting on the very far left, Rule 21 applies where the point of interconnection is on the IOU-controlled distribution system, and where you're on the customer side of the meter, so the intent of the program that you're participating is to enable you to offset your on-site load. And I put the word "compensation" in quotation marks because it is an intentional use by the CPUC of that word, you're not under contract for any kind of sale of your energy, you are happening to receive some compensation should you place some excess energy onto the grid.

And then, if you jump over to the dotted green line, you're still on the IOU-controlled distribution system, but you're on the system side of the meter, so you've participated in a -- or you'd like to participate in a CPUC/DG program with the intentional export and sale under contract of your power. And Rule 21's applicability in the CPUC's jurisdiction is over those interconnections where the sale of your power is at avoided cost to the host utility, that's also called in shorthand the PURPA Contract. And then, in the black outlined box below, I've listed some of the different CPUC/DG programs. Thanks for the helpful use of the cursor.

And then, the reason that a wholesale distribution tariff exists is because there are some facilities that are interconnected to the distribution system, but their sale is on a wholesale basis, so they are not making a sale to their host utility at avoided cost, and that places them in FERC jurisdiction, and I've listed, for example, a Renewable Auction Mechanism, and the RPS and QF Programs where the PPA is subject to negotiation, rather than sort of an automatic tariff. And then the CAISO tariff applies on the transmission system.  I don't think we need to really spend any time on that one.

Okay, the need for reform, so I did say a couple slides ago that the Interconnection Tariffs have functioned, in fact, to aid some of our DG Programs in really getting off the ground and providing for interconnection of generating facilities in very high volumes statewide; however, from about 2008 forward, the CPUC and the Legislature, in part because of new authorizing legislation, created new procurement programs that incentivized distributed generation that exports onto the distribution system.

When you have greater volumes of exporting generating facilities, they are more likely to contribute to penetration levels that will exceed the 15 percent threshold, and that's one of those screens that Linda mentioned at the beginning, they may be outdated, may still be useful, but I know Mike Coddington from NREL is going to speak more to that topic.  But in any event, you have more likelihood of exceeding that penetration level. When you've got a higher volume of exporting facilities that are locating in the same electrical areas, and they are intended to be studied through a serial, one-by-one study process, that process quickly becomes too much for a utility distribution engineering department to handle.

All of these factors can easily lead to increases in developer complaints about transparency and timelines, or ability to meet timelines, and then, last, Rule 21 has long lacked a pathway to resource adequacy value, and even though the authorizing legislation for some of the new DG programs specifically stated that the resources shall count towards the IOU's RA obligations.

With all those factors in play, the CPUC decided to initiate a turbo-charged reform process. We launched it in August of last year. Our initial date by which we wanted to have a completely reformed tariff was December 31st, but that proved beyond our abilities; but, nevertheless, we, after several months of intensive negotiations, a settlement was filed in the CPUC's Interconnection Proceeding on March 16th. We also, over the course of the fall, opened a rulemaking on CPUC's own motion, and its intention was to serve as the forum for an eventual settlement. It also left open the possibility that, should the settlement fall apart, it would pick up wherever those talks left off, or it could take the settlement and consider it, and then move to a Phase II. And that's actually the state where we are now.

The CPUC will likely consider the proposed settlement in the second or third quarter of this year, that will be the conclusion assuming it's approved, it would be the conclusion of Phase 1, and then Phase 2 would be launched very soon after.

So a few details about it. As I mentioned, we received very important technical assistance from the Energy Commission. NREL wrote a white paper addressing the 15% penetration threshold that I think was an important learning document for the settlement parties. We had 80 parties join. The negotiations were held weekly in full day sessions. We ended up having 12 full day, all party negotiation meetings, and there was a core drafting team that really performed heroic efforts, and I actually really need to call out the three IOUs and the Interstate Renewable Energy Council for the incredible amount of work that they did in the drafting session.

Our degree of consensus was actually quite strong. There are 14 Settling Parties and there has been one issue protested within the settlement by DRA, but other than that, as you can see, the Settling Parties represent a wide range of kind of arms length interests about distribution system interconnection.

And I know we have at least one settling party here in the room, which is the Clean Coalition, and I really want to thank all of the parties that came quite a few strides towards the center in signing on.

So just a high level summary of the proposed settlement. The Settlement Agreement, among the Settling Parties, asks that the CPUC approve the entire settlement, and it also recommends priorities for the next phase of reform. The three major pieces of the settlement are the Rule 21 Tariff, and so if anyone goes to examine the settlement, you'll see about a 120-page document that is the core of the Settlement Agreement, and that would be the new Rule 21 that would go on the books if the Commission approves it. It accomplishes some big technical reforms and transparency reforms, which I'll talk about in greater detail in a moment.

The settlement also proposes a standardized Interconnection Request Application that needed updating because the intent is to allow exporting generating facilities to apply under Rule 21, and then it also includes a standardized Interconnection Agreement for those exporting facilities, which is the first time that Rule 21 has had such an agreement, really almost since PURPA was enacted.

And then some pieces of the technical reforms. There are two major tracks for examining or evaluating projects under the Rule. One is Fast Track and the second is Detailed Study. And what I've tried to show there are the broad components of each. Fast Track, which that name is the same as what's used in the wholesale tariffs, Fast Track contains initial review and supplemental review. And within initial review, the best of the existing Rule 21 was retained, and then some important pieces were added, so it grew from -- it's still a screen based approach, meaning you can answer the questions in it yes or no, and thereby move around the game board, as it were, it's increased from eight to 13 screens within an increase in the number of days, exporting generating facilities can apply, storage is eligible, it articulates a transmission dependency test, and it states that, while a resource connecting under Rule 21 is energy-only, resource adequacy is achievable either through the CAISO Deliverability Assessment and, at the moment, it says "or other CAISO approved means," and that pending the approval of the DG Deliverability Initiative, that I think Lorenzo spoke about this morning, that would be another means for a Rule 21 Applicant to achieve deliverability.

Supplemental Review is articulated more clearly within the Rule for the first time; right now, Supplemental Review consists of about one sentence, and now it's got three screens, most important of which is a national best practice testing the aggregate generating capacity against 100% minimum load on the line segment of interest. And then moving -- if a facility can't get interconnection following Fast Track, they would be moved to one of three Detailed Study processes that I've listed there.

New Transparency Reforms. As I stated in the front, one thing that an Interconnection Tariff should do is set out appropriate timelines. The new Rule 21 establishes clear timelines for completion of the study or evaluation by the utility, plus decisions by the Applicant which, as speakers about the queue noted this morning, that's something that's pretty important, it has clear withdrawal standards and procedures, it's got some new first looks, there's a pre-application report and it also requires the IOUs to publish monthly and integrated Rule 21 and WDAT queue, so that would show a developer all of the queued applications on the circuit, or substation where they're interested in proposing a project. It also sets out new dispute resolution provisions, some very specific to missed deadlines because this has been such a source of developer complaints. There are a number of new strategies implemented in the tariff.

And I've just tried to set out some anticipated results from the redesign. I think one of the most important is that the high level of successful Fast Track evaluation for Net Energy Metering customers, that has been the case in California for the last 12 years, should be maintained under the new rule. There wasn't really anything changed and the Settling Parties were very clear about not wanting to hinder the success of Net Energy Metering.

I hope that the new tariff improves the marketplace understanding of the locations where an exporting facility, such as a participant in the Renewable Feed-In Tariff, might be able to have a greater likelihood of passing Fast Track, and I would think that between the tariff and the other new tools, the pre-application report, the published queue, the online interconnection maps, and by approximately a year from now, the first DG Deliverability Study released by the CAISO should provide a much better sense to all California of where appropriate locations for DG are.

All right. And then, briefly as to Next Steps, again, the CPUC is considering the Settlement. I've listed here what the Settling Parties requested, or recommended as the scope of Phase 2. As you can see, there's a real interest in seeing compliance and kind of developing an understanding about how well the new tariff is working, and so I anticipate that part of Phase 2 is going to be trying to assess the success of the new tariff.

The CPUC is also presently considering the Transition Plans that each IOU filed on the 23rd of April, and there will be additional standardized Interconnection Agreements to be filed, and then last will be preparing a staff proposal on how to get at the question of the interconnection success under Rule 21.

And then, last, I wanted to close with just a look ahead and at other items the CPUC is working on. You know, interconnection is -- it can be a barrier to project development at the moment; I think, as we look over the rest of 2012 and towards 2013, a big question is going to be the implementation of the new pieces of the tariff. There are some technical questions that I think we'll need to address, for example, the fact that the Net Energy Metering Program is now open to all RPS-eligible generating technologies, which could create some new detailed studies that the Utility Engineers will need to perform.

The CEC hasn't lost budget, as I understand, for its technology certification work a few years ago and there is a lot of new technology on the market that could perhaps -- a certification process revival might be something to look into. And then, last, on the technical side, tying the functions that we want from distributed generation to the technical standards, such as metering, which was brought up this morning, is something that will come up in Phase 2 of the OIR. And then, last, there are some major policy issues that are not entirely going to be resolved in our proceeding, but we'll at least take a first look at them.

There is a major tension between cost certainty and the volume of queued generation in California, and this is true at the distribution system. The tariff allows you to execute an Interconnection Agreement, but also says you're responsible for any later discovered costs associated with your interconnection, and that simply creates a major issue for developers. We'll address that in Phase 2, and then we're also -- we have several requests for proposals that are getting underway in which some technical experts will be conducting some of the cost benefit analysis that I think California is in need of as we head towards our 2020 goals. Again, thank you for the opportunity to speak and I'm happy to answer questions now or at the end.

COMMISSIONER PETERMAN: Rachel, thank you for that very good overview. A lot has happened since we spoke last about this topic last summer, and I'm looking forward to hearing from the various utilities and working group members about their experience, and if they agree with your characterization of next steps. Thank you.

MR. BROWN: Rachel, I've got just a quick question. I'm excited about the first line in the Technical on page 13, that Net Energy Metering Programs are open to all RPS generator technologies as of 1/12. I must have missed that. How did that happen?

MS. PETERSON: Uh, legislation with SB 489 last year by Senator Wolk was approved and went into effect on January 1st.

MR. BROWN: Thank you.

MR. BERNDT: Good afternoon. My name is David Berndt and I'm with Southern California Edison. Thank you for the opportunity to be here this afternoon. So what I'll share with you this morning is some of our experiences in managing, my role is Manager of Grid Interconnection and Contract Development, so I work with the engineering organization to develop the contracts that fulfill the interconnection requests. So to put it in perspective, I'd like to begin with the first bullet under Process Challenges. Just to keep in mind, the current queue is at 988, is combined of the WDATs, TOs, and the Rule 21 requests, active generation interconnection (IC) requests; but if you put it in contrast, back in 2009, we had 200 and we thought that was overwhelming. So it's continued to grow pretty dramatically.

In terms of the active requests, the number that are still moving forward through our queue, there's roughly 31,000 MW in that queue. And to put that in perspective, SCE's peak is about 25,000 MW on a peak day, so it's substantial. And the last time I checked the CAISO queue, they were at 70,000 MW, so a substantial amount in weighting and study.

The other trend I've been noticing is that there's been an increase in the number of smaller projects, and by smaller I mean less than 20 MW, so that volume has continued to increase over time.

One of the major challenges that we've been facing is the Legacy tariffs and the challenges around how do we move them through to the completion of an agreement. The tariffs aren't that clear on it, and so sometimes they can, you know, basically hold back. We tender agreement, we'll tender a study agreement, or even an interconnection agreement, and they may just hold on to it for some period of time, and that's been an ongoing challenge.

And just to give you perspective on the volume of those, when the transition went from large generator interconnection process to the clustered interconnection process, and then from SGIP to the GIP process, we had about 150 of those Legacy serial projects that were still in queue, and then currently under the transition, we're looking at probably about 500 projects in the Rule 21 arena that are going to be migrated to this new process. So it's those transition projects that create a challenge for us because the timing of those, if you think about it when you look at the cluster process, how it works today, you know, we end up in March closing the final window for a given cluster, and then it goes right into the Phase 1 Study, so our engineers get very busy doing that work, and then, coincident to that, generally you'll have a Phase 2 study that runs from the previous cluster, and so it's a pretty big drain on resources, it's a challenge. But it's not just a resource issue in that you can throw a lot of people at it, but there's a point at which you get diminishing returns, it becomes a challenge, because they all can't work on the same area at the same time.

Some of the hurdles that we're challenged by, we have over-subscribed areas and I would point to the northern and eastern rural areas, basically. And I think it -- part of the challenge in that is from above -- there's a real system load which is like in the northern area, where it is physically constrained today, and then in some of the eastern and some of the other areas in northern, they're subscribed, but they're subscribed by capacity reservation so to speak, and that creates a challenge for us, as well. And so they create these layers, basically, of requests.

The next bullet around hurdles says "Load remote projects," and it really -- it should say "Load *and* remote projects." But the point I'm making there is that, when you look at a rural area and you don't have a significant diversity in the load that those generators may be serving, we design for assuming that load will be in place throughout the duration, or through the time, and if it's not a very diverse load, meaning a customer, or two customers, if one of them leaves, or something happens in those rural areas, what happens is then you can overload the transformers from the generator trying to get out to the transmission system. And that's going to be a significant problem, I think, for us going into the future.

And then, when you look at the urban areas, the challenge, I think, is going to be a cost issue and it's going to be also around Undergrounding. I think we're going to have hurdles in both those issues.

For Process Improvements, we've been working to manage those serial Legacy projects that I talked about for some time now, and what we do is we really found that it takes getting it to an Interconnection Agreement, we sometimes, because of the age of them, have to re-study them because that's a very dynamic environment, and so things continually change. As projects come and go, either they withdraw or they move forward, and so we have to go back and re-study some of those projects, but it's been an effort that we've been doing successfully, I would say, today in working through trying to get those removed. Still a challenge.

The other is the reformed Rule 21 process has been -- we're looking forward to the outcome of that, we think that will add more value to the process. In 2011, and let me just put my experience with this group, I started at the beginning of 2011, so I've been there about a year and five months, and it's been a very interesting road, to say the least. And what we did was we structured the group -- my predecessor, for example, had 16 direct reports and growing, and it was starting to become a challenge, and so we've restructured, having three subordinate Managers, one manages what we call our Resource Planning and Performance Management Group, which helps us with some of the back office things, data management and does a lot of the process work, process mapping, process improvement. And then two Managers that manage Project Managers, that work with the interconnection customers in moving their contracts through to fruition. What we have also done is we've managed our resources such that we've brought in scalable resources, being the contingent workers, and consulting folks that can help us and do it in accomplishing all that work. At some point, and I thought it would have been by now, that we hit a stable point, and every time that I think we're going to do that and it's going to crest, it doesn't crest and the peak keeps rising, so it's been a challenge to figure out how to staff for this, you know, when I look at the volume that is in the queue, I've assumed, and maybe incorrectly, that we would be hitting a plateau soon, but it hasn't and so we continue to scale our resources accordingly. And, again, the point I wanted to add there was just the diminishing returns on staff increases; at the engineering level, there's a point at which it just doesn't help anymore, and even so with completing the agreements.

Some of the things we've done from a process standpoint, we've implemented an electronic approval process. For our organizations to look at an Interconnection Agreement, there's several disciplines that participate in those, to the tune of about 11 different organizations, and to get them to all have reviewed it, an agreement, before it goes out the door, becomes a challenge.  So we've been able to put together an electronic approval process that has made that much more thorough, and it helps us to document well any changes or anything that happens in regards to the contracts.

The other thing that we've done is we've been working on creating templates to try and  make it more simple and streamlined, so that in a review process, we can look for redlines, as opposed to each agreement being built from the bottom up every time we go to negotiate an agreement, which also is a benefit of the settlement process.

The other thing is we work in cross-functional teams throughout the organization to make sure that we're working hand in hand, so that as the engineering group is working towards the completion of a study that is handed off well to the contract managers and the contract managers then with the interconnection customers.  The other thing is we've been participating in the reforms to ensure that they make sense and they're going in the right direction, as well.

The other thing I think important to maybe add to this side was, you know, we've also I think last year implemented our capacity maps online, as well, for the interconnection customers to be able to look.

Some of the study results, what's been happening. Forty-four percent of the projects that qualified for Fast Track have been going through and they've qualified for Fast Track; 28% of that total was qualified under Supplemental Review, and I think it's important to recognize, though, that in that statistic that we had a particular developer that had approximately 24 applications that were submitted in there, we believe, in a misunderstanding and so they were rejected, which threw off that statistic, so really probably closer to 70% probably would have made it through. And so that's between January of last year and March of this year.

And just a recent turn of events, since the closing of the second window for the Wholesale Distribution Access Tariff in March, we've had roughly 47 requests for Fast Track applications. So we'll be anxious to see how those flow through the process.

So requests for independent studies have increased. Twenty-five projects were scheduled for the independent study process between March of last year and April of this year, 12%, three of them have signed agreements and are proceeding with construction.

The Wholesale Distribution Access Tariff

Cluster Study approach, we definitely find is much more efficient. When we look at -- and Rachel talked on it briefly a few moments ago -- the serial process just for the volumes that we're talking about, is just not going to work, and so we're even running into challenges in the cluster timing such that, if we can't get everybody moving along toward an agreement in a certain timeframe, it starts to become a challenge for us, as well. And that's going to be an ongoing issue, I believe.

The look ahead. The proposed settlement agreement, I think, is going in the right direction, and the reforms should improve the interconnection results. I think the challenge included in that is going to be the almost 500 Rule 21 applications in that transition plan that we've laid out, and I think just making sure that we can get them through in a timely fashion is going to be a challenge, and looking to do that by October.

And I think it's important to add here that maybe a cautious going forward in program development, what's happened is -- when I look back at each time we went from like the large generator interconnection process to the clustered, then we went from the SGIP to the GIP and then folded them altogether, and then we have 2.1, and now we have 3.0 and the challenge is, each time you have these Legacy tariffs that you manage to, and with programs it can be the same way, I would just caution us that, as we continue to do that, we move slowly in that sense. And the other thing is I think the challenge would be as we look at the volume, we just have to be able to recognize that there's going to be exceptions and things that happen when the volumes increase or surge dramatically. And that's it. Thank you. Any questions?

COMMISSIONER PETERMAN: David, thank you. That was very useful. I appreciate particularly you talking about the process improvements that Edison has engaged in. I recall in a workshop last summer we were asking that question about what could be done to improve the process, and I appreciate your efforts to increase the staffing and also acknowledging some of the diminishing returns to that.

I wanted to ask you a little bit about the distribution maps that Edison has now provided publicly, as well as the other utilities, 1) to what extent have you seen those maps be beneficial since you started putting them online and in terms of having people submit projects that are more preferred areas? I know it's still early on, relatively, but….

MR. BERNDT: Yeah, good, good and not so good in that we're received both positive and negative feedback of them, so --

COMMISSIONER PETERMAN: What is the negative feedback you received on them?

MR. BERNDT: That oftentimes they'll go into an area, and it's hard to find a green area, and when you do, the capacity might be limited or that it is already being spoken for, you know, there's multiple people trying to speak for that same capacity, so it's hard to keep them updated fast enough.

COMMISSIONER PETERMAN: That was my second question about, considering that the landscape is changing very quickly in terms of how frequently can you update the maps, what would be a reasonable time period from your perspective?

MR. BERNDT: I can't speak to that, but I'll definitely get you a response to that.

COMMISSIONER PETERMAN: Great, thanks. I don't have any more questions at this time.

MS. WINN: Good afternoon, Commissioner Peterman. Valerie Winn with PG&E. And the slides that I have today are going to be very focused on our WDAT process. I think, as Rachel outlined earlier, there are really three different processes that people are using today to interconnect through, and that's our Rule 21 process for the Avoided Cost contracts, the Rule 21 process for NEM contracts, and then, of course, the WDAT. So before I go to the first slide to talk about the WDAT contracts, I did want to note that, under the Rule 21 for the PURPA contracts, right now, you know, the applications under that process have been fairly steady, and we get about 50 applications per year, and that's been no real spikes there as we've seen in the WDAT. But with SB 32, as well as with the passage of SB 489, we're kind of expecting to see more people applying through this process, but the timing of getting those applications is very unclear, so more to come as we look at that going forward.

Under the Rule 21, the Net Energy Metering process, PG&E has interconnected thousands of people through this process, and that study process generally takes about two to three days, and we've completed about 95% of those applications within that time period. So that's been very successful. The average size of the generator, though, interconnecting under that is about six kilowatts, so it's really really itty bitty.

So as we go to the WDAT process, if we could have that first slide, as you can see from 2000, not many applications at all under that process, and a multi-fold increase, really, from 2008 through 2011, so far this year 250 requests have come in and cumulative over the period, I believe it's about 450 requests we've received, and about 321 requests are in our active queue today, and that is about 1,650 MW waiting to be interconnected.

So under the WDAT process, we've talked about some of the different processes that are there, we've got the Fast Track process, we've got the Independent Study Process, and we've got the Cluster Study. And as you can see here on this next slide, the previous slide showed the interconnections by year, and this is just breaking it down to a monthly view over, you know, since the beginning of 2011, with a peak in the request in March of 2011. And I'm not certain what was driving that peak. And then so far this year, the peak monthly applications have been about half of the March 2011 peak.

So as we look at these when we're going through the Fast Track process, next slide, and unfortunately these numbers on the Fast Track Statistics aren't perfectly synced up with the previous slide, we might say March of 2011, oh, you've got 70 in, and 45 of them you might think qualified for the Fast Track process, but there's a little bit of a lag on some of these from period to period. So, in March of 2011, though, where there were 41 requests for the Fast Track process, only about 15 actually passed that Fast Track screen, and that's primarily because the average size here under our

Fast Track process has been just under 1.5 MW, about 1.4 MW. And most of these projects have been in rural areas where the peak load is quite low, and so screen 2 of the Fast Track process limits you to you can't exceed on that circuit more than 15% of the peak load. And so, as a result of that limitation, most of the projects aren't qualifying for the Fast Track.

We've seen over the period about 20% of people qualifying under Fast Track, but we actually expect that to decline as the project sizes get larger, because, again, that not to exceed 15% criteria, you know, really limits larger projects on many of those circuits. If we look at the next slide under the Independent Study Process, of course, as you can see, compared to Fast Track, fewer people qualify for this Independent Study Process. The people who are not Fast Tracked and are not the Independent Study Process end up in the Cluster process. How this Independent Study Process and the Cluster Process, there have been a lot of reforms and changes since March of 2011, but I think we're still looking for some more time to pass to see -- and to incorporate some of the lessons learned, so I wouldn't say that these results are terribly indicative of what we might see going forward, but that's just an update of where we are now.

Generally, under the Independent Study Process, you need at least six to nine months to do the study, and then the interconnection itself would probably be another year or so behind that.

But in terms of the improvements that we've made in our processing of the applications, I would note that we have added additional staff through expanding our Generation Interconnection Services Group, and we've also added some other technical parties to conduct the studies. And, like Edison, we are continuing to evaluate the resource requirements and adjusting is needed. We've also transitioned from a customized distribution planning tool to a more power engineering software that actually helps us do more robust analysis of what the impact of adding more generation to the distribution system will be. We're also in the process of transitioning some of our database information to more of a workflow management tool, and all these tools, we're hopeful, will just help streamline the process and provide us a better over-arching tool with timelines and triggers to move projects from one milestone to the next. So those are some of the staffing reforms that we've put in place.

As far as some of what we need going forward, I think Edison highlighted a few of those items, but I think we also, you know, at PG&E we're also very interested in the research results that we'll be getting in over the next few years.  For example, just last week, the Energy Commission approved a $1.5 million research grant for us to actually get information in the field through a feasibility study on dynamically regulating the voltage on some of these distribution feeders, and that sort of research can really help inform, you know, real world experience, what we need to do to improve some of our systems.

We also need to look at more robust trip schemes and also incorporating better computer programming and modeling of a system that's much more dynamic than what we have today.  I'm happy to answer any questions you might have.

COMMISSIONER PETERMAN:  Thanks, Valerie.  Just one follow-up question.  You mentioned that the share of peak load constraint, there being a binding reason why a number of projects did not make it, the Fast Track process.  Are there any other criteria you want to highlight as being key criteria for getting certain projects screened out?

MS. WINN:  No, that's the one that immediately springs to mind as one of the limiters, the primary limiter.

COMMISSIONER PETERMAN:  And also, regarding the

Distribution System Maps, have you had a similar experience that David spoke about with Edison?

MS. WINN: Yes, I mean, it is a very dynamic situation and certainly, you know, the first actors are going to be locking up those positions very quickly. As far as how quickly the maps can be updated, you know, that's always a challenge because it's such a dynamic situation and you've got resources focused on processing, and then how does that loop back with updating the public tools.

COMMISSIONER PETERMAN: That was my thinking, I'm sure you could do it as quickly as possible, but I was more interested in the usefulness of -- what would be an appropriate updating period, acknowledging that it's never going to be as up to date as we all would like?

MS. WINN: I can't really say. I know that we're probably updating the maps, though, at least twice a year to coincide with our Renewable Auction Mechanisms discussions, and the, of course, we all have photovoltaic programs, as well. I'm not certain how frequently those maps are updated there.

MR. BROWN: Yes, Valerie, you mentioned that you've had some improved software tools that you've used for analysis. We're shopping for new tools, too, can you throw out a name or two of something that's really working for you?

MS. WINN: Well, the one that was noted was the CYME, I'm not sure how you -- what that acronym is. And then I know that we've also -- I know we have a proposal pending right now before the CPUC to work with Lawrence Livermore National Labs to kind of incorporate all of this data that we're getting in and to help us design some better modeling tools that could really leverage that information for utility planning, so that one is kind of in the works. We'll see what happens there.

MR. BROWN: Fantastic.

MR. PARKS: Good afternoon. My name is Ken Parks. I'm with San Diego Gas & Electric Company. Thank you very much, Commissioners, for having us here today. We kind of took a different approach this afternoon, kind of a layover of all the distribution system. My responsibility is only on the distribution side of the house of SDG&E, so we won't talk about the interconnection process. I think the key slide on the next slide, the key point is that SDG&E's distribution system, the voltage is at 12 kV, 12.47 and below. We have nothing higher. This 6.9 level, anything above 12.47 is transmission level, and so it makes us a little bit more unique and maybe not so renewable friendly because of the back country that we have in the rural area, it is kind of a dynamic system back in the back country.

We wanted to mention that our responsibilities is anything, any tariff that is connecting to the distribution system, it could be running in parallel, or actually feeding to the utility. Next slide, please.

So it kind of gave me a snapshot overview of what's on a distribution system today. Today in Net Energy Metering, there's about 17,000 customers that are on any -- 130 MW on Nameplate rating. The DG projects that are already interconnected into our distribution system, you can see them listed there underneath there, totals about 470 MW, and then the pending projects that are out there today for biogas, fuel cells, and some fossil fired engines, there are about 20 MW that are pending.

Then, on our WDAT queue, SGIP, there's 111 MWs pending and we're working on, and we have one LGIP project on the distribution side trying to connect 40 MWs on the 12 kV system.

And then we kind of looked out at the forecast, what does it look like when we take the numbers that we have today, kind of multiply it out for Net Energy Metering, and we're kind of projecting through 2016, we kind of predict we should have about 15,000 new Net

Energy Metering customers by the end of 2016, addition of 125 MWs of Net Energy Metering customers, and then you take the RAM, FIT, and SDG&E Solar Initiative Program that we have, and also SB 32, we're somewhere around 1,300 MWs at the end of 2016, or approximately there. That's just kind of a quick snapshot of what we have today.

And this is just kind of an overview of San Diego County, we're just kind of that sleepy town that's down in the south corner of the state. But if you notice the yellow sun, those are the projects that have been completed within our service territory. Look at all the gray suns that are out there in the rural area, you know, some people refer to it as a weak distribution system, I wouldn't classify it as weak that we're meeting our customers' needs, but it's a very small system, typically it's a number 8 copper wire only good for 180 Amps, 150 Amps, something like that, but large solar projects are trying to tie to that distribution system back in the rural area.

Under the Net Energy Metering Program, they stated well already that it's been a very successful program, even within SDG&E. We're authorizing about 350 new customers every month, somewhere around 2.5 MWs of energy per month, and most of those are residential customers.

Then you just look at the cumulative chart as it grows, last -- well, end of April 2012, we had almost 17,200 customers under Net Energy Metering -- 132 MWs. Then we've just kind of projected what Net Energy Metering would look like, this came from the CEC in December 2009, and the projection they forecast was somewhere around at the end of around 2020, about 300 MWs. Today, our active count is about 132 MWs, but if you take the recent numbers, we believe that at the end of around 2020, we should have close to 450 MWs just Net Energy Metering, if nothing changes.

So in our Feed-in Tariff as of 2011, we received on the third quarter 13 applications of 18.5 MWs, in the fourth quarter, five applications, and then today, active that's in the queue today, we have 10 applications of 14 MWs during the second quarter of 2012. This is for the Feed-in Tariff.

Then, under the WDAT SGIP, prior to 2011, we only had four applications that had ever been submitted to SDG&E, but in 2011, for us, it was a huge increase in rush, the first quarter we received 21 applications, second quarter, 11 applications, and the fourth quarter, one. And as of today in our queue, we have 23 applications that we are in the process of feasibility study or system impact studies to be completed within the next few weeks, and we already have some of those results already out to our customers.

So what are the experiences and challenges that SDG&E has seen? Just in the year or so, as you notice, that's where really our work has really increased. The in-rush of applications are challenging because we have limited company resources such as Distribution Engineers to work on the projects, and try to meet the timelines that are set within our tariff, it's very challenging for us at this time to meet that.

The other challenging part is that the tariff does not give us a reasonable way to communicate to our customers when we see projects that are not going to be successful, we have a substation and the capacity is 7.5 MWs today, we have six Feed-in Tariffs at 8 MWs at that substation, then last month we had another application that was submitted to us at 40 MWs on a circuit -- our largest circuit is 10 MWs. As we negotiated with this developer, talked to him, told him that the information as far as the substation's capacity was 7.5, on the queue, he can see that there's 8 MWs ahead of him, we still have to use our resources to study these projects and go through the steps, so we have no other choice but doing that; it ties up resources that you could use on other projects that could move farther ahead.

We just kind of threw this same kind of sad fact for us out of the Fast Track applications that we received last year, 14 of them, only one passed the Fast Track screen. Once again, it's in the rural areas of San Diego County, it's very difficult for the distribution system out there.

So what have we learned in the last year or so? Location, location, location is the key for our developers. If you're going to spend a ton of money, you want to get into the load areas of San Diego County, which is next to the ocean, where the population -- very expensive, very tough to do, right? Or, in the rural areas, you want to get to the substations, get closer to the substations.

To answer your questions ahead of time, our map, I think, has been very successful. We have actually combined our queue with the WDAT, Rule 21, so all the Feed-in Tariffs and WDAT customers that are out there, they can see what's ahead of them. So I think our map has been very successful to help our customers to kind of locate what -- first they look at the queue, then look at the map, you know, to reconduct our distribution system, it's roughly a million dollars a mile, you could buy a lot of land if you can get closer to that substation if you want to be successful. So I think it's been very successful for us.

Some of the challenge is the voltage issues, as you can see, high voltage at the point of interconnection, current flow back to the substation can negatively impact, thus voltage and adjacent circuits. Regulators lock out with current flow in reverse direction. And it's just, for us, we're on a learning curve on the distribution side of how to take that kind of generation into our substation.

So what are the activities within SDG&E today? Under our SGIP Program, or WDAT SGIP, we're in the process of modifying our tariff. We hope to file it by this June with FERC, and some of the highlights we want to change in our tariff, we want to eliminate the feasibility study. We feel like we can give the contractors, the developers, enough information in the scoping meeting to make a business decision to move forward, and that would save us 50 business days alone, just by doing that. The next step is we want to, in lieu of a site control, they could offer $100,000 for a deposit in lieu of a site control. And then, also, we want to take our deposit, instead of $1,000 to get into the queue, take it to $50,000 plus $1,000 per MW, and hopefully this will help alleviate some of the -- some of the people are just -- we call them "queue hogs," you know, are just sitting in there and just taking up the resources from the utility.

And the last item that we're looking at is Engineering and Procurement Agreements. When we get into a design after a feasibility study, a system impact study, if the developer is in agreement, we would like to enter into a contract with them where we could start designing the project, look at right-of-way issues that may be on the project, environmental issues, and try to define them upfront and run the project in parallel instead of doing everything serially to help speed up the process. Next slide.

Well, when SDG&E started to have the influx of applications coming in, we did a realignment of our distribution interconnection process and we consolidated everything into one group, and one group was called the Customer Generation Group. They had the responsibility of, as I mentioned, anything that ties or parallels the grid on the distribution side. So it's kind of a one-stop-shop, that way a customer developer always knows who to contact within SDG&E. We ended up adding two FTEs on the Customer Generation Section to help alleviate some of the work. We are working with the engineering folks. We are consulting, hiring Consulting Engineering firms to come in and help us with the distribution system, to help us meet those timelines within our tariff, so we wouldn't be late on the reports that are being established.

We are also developing and improving a brand new database for all interconnections within SDG&E that will help us with the in-rush, and also it's going to help us maintain more detailed records that is coming into the utility and our turnaround timeframe.

And we're also looking forward to purchasing software for dynamic analysis on the distribution system, to help us to solve the problems ahead of time. Thank you. Any questions?

COMMISSIONER PETERMAN: Thank you. Could you just say again, what is the timeline for your tariff?

MR. PARKS: We hope to file this June, which is next month.

COMMISSIONER PETERMAN: I appreciate your comments, particularly about interconnection in the rural communities, we've heard this from PG&E and Edison, as well, and it's an issue we need to consider. No more questions, thanks.

MR. BROWN: Good afternoon, Commissioners. I'm Dave Brown from Sacramento Municipal Utility District, and I'm just going to go quickly through a couple things. This is a lot of the issues that our Investor-Owned

Utilities are experiencing. We don't really have comparable issues, though; we don't have a WDAT, and we basically just extend Rule 21 to cover a whole lot of stuff. And it does tend to keep things a little simpler for us.

Most of our interconnections are coming from the Net Metering Programs, and that's going well and, just like earlier speakers, sometimes they get a rush on that and we don't know why, like we'll be cruising along at an even level, and then it will double for a month, and then it will go back down for a little while. And it seems to be some of the same months, and so it's statewide. I don’t know exactly what's going on there.

We did issue our Feed-in Tariff about two years ago and, as far as I know, all of the capacity is filled that was originally committed under that Feed-in Tariff, and is running nicely and giving us a few operational learning experiences. We're also looking at utility-scale projects to take advantage of some of the costs that are available today, but about a year ago we implemented an electronic approval process that streamlines the processing of the project to make sure it gets usually about four touch points we need, the engineering review, the metering, the new business connect-type issues, and make sure we get it logged in and tracked properly -- and get the rebates, obviously.

We're still receiving a number of unsolicited proposals and following those up. One of the issues that we have, probably structurally, is that we're getting more and more of our projects coming in as leased projects, rather than customer-owned projects. The State of California is putting in a fairly good-sized system at Folsom Prison, and the State doesn't have any money, and neither does the City, to speak of, so they're taking advantage of these lease programs, and it's working really well for them, as it is for a number of our residential and commercial customers, some of the large box stores are taking advantage of that, as well. What we lack yet, I think, is a model that works really well for multi-family, low income to take advantage of that.

We're doing, as most utilities, something we call Virtual Net Metering, and it seems like that's just a little too complicated because we don't see a lot of developers do a second one. They come in and they do one, they get through it, and then we don't hear from them again, the next project is somebody else. And perhaps they learned the better of it, but it is a bit of a challenge.

In terms of our interconnection costs, connectivity is one of the main issues; we've got some very low cost land, but it isn't located near our feeders, we get past that, but for the most part our map directs people away from those areas, and whether the map works or not is kind of one of those things that it's hard to tell, if it works, you would never know. When it doesn't work, you would know. So I get calls from developers when they don't have the information that they need, when they need more information, so the lack of calls from the developers might mean they have the answers they need and it might mean they're not out there, but it does look good. And what we're trying to show on the maps is where the low cost interconnections are, and that's kind of -- it's not an unlimited resource, but at present there's a lot of good resource out there, a lot of good locations.

The next item, telemetry. Our operations has -- when I first asked them, "How much telemetry do you want from all this stuff," they said, "Don't even bug us until you've got a couple hundred megawatts." Then, when the Feed-in Tariff went out and we started getting that first 100 megawatts, they said, "Whoa, wait a minute, we need telemetry." So we're giving them the telemetry. The Net Energy Metering, which we also use much higher than one megawatt sized projects, we bring telemetry back from that. But we've taken the SB 1 Rules to mean that we can't charge customers for telemetry when the project is under one megawatt.  But a lot of folks at our company want to see telemetry at about 500 KW because they feel that so many of those projects, the box stores, the large warehouses, are coming in at that 200 to 800 KW size, and they don't want to lose the ability to watch that.  And what we've determined is that, if the tariff doesn't allow us to charge them for it, but we want it, we'll put it in at our other ratepayers' expense, which is something we really don't like to do, and we're trying to build a business case for doing that.

One of the things that we need, and I think everybody would look to, is a less expensive way to do the telemetry.  Some of the things that we've tried to bring the cost down is buying meters that are ready to go with the protocols for communication right into RTUs, and streaming data back to the utility.  This is -- at one megawatt or larger, we want the data live and streaming every three to five seconds like we stream data from all of our own facilities.  And we've had some success with that, but when we have an internal telecommunication department that's used to building things for large power plants, they tend to think in terms with one more zero on it than we're used to seeing when we're talking about distributed generation.

And then, we have yet to see, thankfully, some of the -- on the next bullet -- the equipment operating impacts, we haven't had a lot of trouble yet, and it may be because we've been so conservative, but in terms of voltage regulation equipment overworking, working too many steps, wearing itself out, capacitor banks switching on and off too much, those are stories we hear about and we haven't seen yet, thankfully, at the penetration levels we're currently at.  Next slide.

I'd just like to share a few of the observations that we've had in the last five or six years.  Whenever you've got load in excess of the generation, almost all the technical problems disappear. The interconnections are real easy.

And the next one is, the distribution system reliability has not been degraded or improved by DG, it's kind of neutral.  And it's largely because most of the stuff that we put in is designed to not disturb the distribution system, and that's what we're going for, and so it -- and also, for protection purposes, it's designed to get off at the first sign of trouble, so it doesn't tend to help ride-through, either, through system events. But, to date, that hasn't been a problem, but we're addressing that.  And we're looking towards the IEEE 1547.8 and some of the other standards bodies to help us with perhaps some future designs on that.

The next bullet point, Inverter-based technologies, they make things simple. We're now getting almost all of the rotating machinery in Inverter-based. The Tico Gens and other generation systems are coming in with Inverters, so we don't have nearly as much issues to worry about. have less impact on Voltage, Flicker, and Protection, compared to rotating machine (Synchronous, and Induction) generation.

I'll just skip down to kind of cover -- DGs are rarely beneficial to the system -- I said "rarely," I didn't say "never," they're just rarely beneficial because they're not generally located for our benefit, they're located for, if it goes on the roof of a Costco, it's for the benefit of a Costco, it may not be that that's the best place in our system for it, but they're paying for it, so they get it where they want it.

And you've probably seen all the curves, I didn't bring all of them, that show that the rated output of most of the PV systems is only about coincident 40 percent with our peak, and residential, it's almost not coincident at all in the residential areas.

The questions that we're looking for next is, is when we've connected all that we can reasonably connect to a distribution system, what do we do next?

Especially when we're talking about the small customers. When we're dealing with the large developers, we've got a lot of practice in that. But when we reach too much in residential subdivisions, we're not sure where to go next.

And just the next slide on Mitigation, one of the sayings that we use is, "When a DG becomes the tail that can wag the dog, find a bigger dog;" with our Feed-in Tariff projects, a lot of them were proposed on 12 kV feeders, we moved them up to our 69 kV, which in contrast, in our system it's still distribution. We're using Transfer Trip on a number of our systems, but what we find is it's not cost-effective for the smaller systems, anything under 500 KW, it can almost kill the project if that's necessary.

Anyway, I'll just skip right ahead to asking if there are any questions because I know we're short on time. Thank you.

COMMISSIONER PETERMAN: Thank you, appreciate your presentation and particularly your comments on Telemetry, it's an issue that we looked at last summer in some of our workshops, and looking at some of the experiences in Europe. I was wondering if you had a sense of what share of the overall, for example, PV system cost would be for telemetry equipment and whether that scales with size.

MR. BROWN: Yes, it doesn't actually scale with size, at least the way we're doing it at SMUD. It's basically take the output of the meter and sending it back on a phone line, or a fiber optic line, and so it really doesn't scale with size. And ideally, we'd like to see that come in at somewhere under $15,000; whereas, by the time we get the communications onto that, and especially if we go fiber optics, it sometimes gets into six figures, and we'd really like to get that down.

CHAIRMAN WEISENMILLER: I guess one question I had for you is, when we had our workshop, I think it was last week, we really heard a lot from Environmental Justice community and Local Government and, of course, they were all pushing us for the "please locate the DG in the urban areas, particularly in the adversely impacted Environmental Justice communities." And so, again, we're trying to figure out how to reconcile that push with the more electrical engineering realities of your system.

MR. BROWN: Well, those are places where it's inherently easy to interconnect, where it's easy to serve customers. I've seen some projects that are designed around large apartment complexes, especially like the ones where they're covering all the parking structures with solar. Those work out very nicely from an electrical interconnection standpoint. The challenge is predominantly around the idea of sharing the benefits and getting the interconnection to work from a business standpoint, so it's kind of the non-engineering part of it.

MS. WINN: And actually, since I participated in that workshop last week, one of my observations is I looked at some of those maps that were presented by the Environmental Justice community, if you're looking at adding solar in those communities as a way to create jobs, I think it would certainly yield that benefit. But from a pollution reduction perspective, my perspective as I looked at some of those maps was that those locations were along major highways and, in all likelihood, the higher emissions factors were likely coming from transportation, and so some of the public health benefits from reduced asthma would not be addresses, really, but putting more solar panels in that area, they wouldn't address the transportation issues.

COMMISSIONER PETERMAN: And another area that was identified by a number of groups was the desire to see more DG in the Central Valley, and in agricultural communities, and so I'm trying to get some perspective on how rural is rural when you talked about some of the rural challenges you face.

MR. BROWN: Well, for us, rural in our Feed-in Tariff was Galt. Are you familiar with the area here? Galt turned out to be a good place to connect, it wasn't too rural. For us, it's near, as I mentioned earlier, a diverse load center, so if you have a good diversity in the load, that's fine in a rural area as long as there's transmission to support it.

CHAIRMAN WEISENMILLER: I was going to say, actually, I think the area that the rural area that we were talking about, people were talking about wildfires and how basically thinning the forestry could help reduce that and hoping that maybe you could get DG to work there. I think they're talking about a CHP application with gasifiers. So, again, that sounded like really really remote.

MS. WINN: Yes, out in some of the forest community areas, they were looking at projects with under three megawatts, and I guess we have been -- PG&E has been in touch with some of these -- with the Forest Service and others to discuss these projects, and I guess one of our questions is really, you know, how sustainable is that fuel supply to run these facilities? But we are in discussions with them.

MR. ISERN: All right. Chair Weisenmiller, Commissioner Peterman, and Commissioner Florio, thank you very much for the opportunity to speak today. I'm Hans Isern. I'm the CEO of Silverado Power. Silverado Power is a developer of wholesale PV systems. As you'll see on the next slide, we're active in seven states and we have about 140 projects, about 15 different interconnection processes, so we have quite a bit of experience in different areas.

This presentation is really focused on distributed generation. We're active in transmission, as well. And it's also focused more on our ideas for some solutions. I'm sure you're aware that developers love to complain, and we're very good at that, but sometimes we also need to try to work together to find solutions to improve.

So if you would just look at the next slide, you can see, this is a map of all of our California projects. We are active in some of the "rural areas" or "quasi-rural areas," we're in Fresno County, Antelope Valley, and then we have some strategic projects along the Devers Palo Verde line, Sunrise Power Link, and some in San Diego County, as well. If you would just move to the next slide?

We're trying to come up with a good strategy to really reduce interconnection costs. And a lot of credit, I think, goes to the PUC and to utilities because they did coordinate interconnection and procurement. I think we've been very pleased to see that the utilities now add network upgrade costs to PPA rates when calculating total ratepayer impact, before they sign new PPAs. I think this was a major shift that happened a couple years ago and it's been very well received and it provides that economic incentive for developers to site in the right spots. That also gives a huge economic incentive for developers to reduce interconnection costs just by acting smarter, being a better developer.

We try to locate as close to load as reasonably possible. Obviously, we can't be in downtown Los Angeles or San Francisco, but we do try to get close to the local load centers, or try to find pockets of capacity and cluster our projects there. I think that's been very successful for us as a developer, but it looks like it might change under some of the new PUC rules where there is a proposal for "Anti Daisy-Chaining." And I think that will create a disincentive to smart development. What it means is that a developer can really only locate one project on one piece of land. We've seen huge economies of scale on land costs, on interconnection costs, on telemetry costs, etc., when we can have multiple projects sharing some of those costs. When you think about it, the minimum cost is maybe $400,000 to connect on a distribution line in any of the IOU territories; for a three megawatt project, that's about a five to 10 percent cost savings that could be had if we could co-locate.

Going on to the next slide, we spend a lot of time thinking about what the perfect interconnection process would look like. We think it's in the intersection of something that's fast, accurate, and fair, so really the gold standard in the middle there, it needs to achieve all three of those metrics. And I think those are the three key metrics that we should be focused on.

To date, I think speed has been the biggest challenge for us. Delays have been pretty common and, in the new processes, all of the cluster processes are 500+ days. That means that new requests starting today won't get agreements until 2015, and there still is time needed to design and build interconnection facilities, which makes us ineligible for the ITC.

I think what this really means is that there's a limited time opportunity to transfer money from the U.S. Treasury to California to support renewable development, and the cluster process, we think, we need to focus on developing a good transition program for projects already in the cluster process, and then beyond that, focus on other processes that are not the cluster process, such as the Independent Study process and the Fast Track.

Generally, I think accuracy has been pretty good. We acknowledge it's a very difficult task. There's been a lot of queue activity. We think that re-studies will absolutely be needed because a lot of projects have been dropping out in every area, so we would love to participate or try to work with the IOUs on some of those items because our goal is really to maintain as many viable projects in the existing clusters as possible, so we don't have to start over again under a new cluster, and then miss the ITC window.

And then the last point, we think fairness has been moderate. We do think there could be some other opportunities for developers to, quote unquote, "argue" or state our case more. I don't think that we've been a huge fan of the dispute resolution processes which is basically, if we complain about an item such as a timeline getting missed -- and there are commercial implications to us -- there's very little recourse for us to do that.

And then, also, I think there could be a phenomenal opportunity for utilities and the Commission and developers to work together to figure out how to clean up the unviable projects out of the queue. That causes a huge issue for everyone involved because they're basically "queue hogs," as Ken said, and there's very little that can be done under the current process to really get those projects out and make sure that we're focused on the viable projects.

Looking at some more specifics on this slide, I think that we have to improve speed. Really, it's all driven by the ITC, that's why you've seen this huge volume of projects looking to connect, that's why you're going to continue seeing huge volumes under the Fast Track and Independent Study process. It's really all about having developers be able to get a cost advantage that we then pass on to utilities and ratepayers. So, really, improving speed is critical for us. That means, you know, faster study turnaround by utilities, I think it means sticking to deadlines on both sides; I know developers can be guilty of delaying, as well. I think the more we can standardize forms we can get out of some of the legal and engineering review that goes into it, so if it's a very clear form that we have to fill out, I think that could prevent some of the back and forth.

And then, also, having frequent updates to tell developers "get out of the queue." We shouldn't have to wait for a study if everyone knows it's a terrible location, or a terrible area. I think most developers would appreciate knowing that from the utility as soon as possible, and for the most part they do a good job in the scoping meetings, but more regular updates are not necessarily waiting for the formal study to have final sign-off by Legal before it goes out, I think, would be really helpful for us because, as a rational developer, we don't want to hold up the process anymore than the utilities want us to.

And then I think the final bullet point on this slide, I think market-based mechanisms are very very effective in directing developers. We live in a fairly high-risk, ideally high reward world. So we do a lot of economic analysis around all of our projects. If it was possible to particularly post study results online, I think developers could learn from that. They could see the project that could be in a very similar location, they could get a really good feel for what the costs were in that area, we've seen this under other utility processes outside of California, where we can actually pull up old studies from other developers. So that's been very helpful.

And then I'm not sure of the ability to do this, but we would love more information on loading and transformer and line capacity, so to the extent that we could have that information shared, I think it would be a lot more helpful than some of the maps which we have struggled with.

For a few additional items for consideration, on the Fast Track, I think there's a lot of efforts underway to improve it and we're very supportive of those. We really like the idea of focusing on minimum load instead of 50 percent of peak load, it just makes a lot more sense to us because that's the amount of load on the circuit, whereas the other one is more of an approximation if there's impact. We also are very supportive of looking at the time that you're producing power, compared to the time of the load, so you should be able to match up those curves. It might not be a perfect match, but we do think there are benefits, especially for PV. So if you look at minimum, say, daytime load, or minimum load at, say, noon for a PV system, that's when a PV system provides at near maximum output, and then you might have a different load curve for wind where it's looking more at nighttime load, or since wind is more variable than the sun, potentially you could use just a straight minimum load for wind.

On the next bullet point, we think consistent, fast policy is critical. We need to work out transition plans for the existing queues, just like utilities don't enjoy having stranded assets, developers don't want to have to strand generation assets because there's been a process change midway through, and we've been waiting on studies, so I think that we'll look forward to working with Rachel on the Rule 21 transition plans, and then there's other areas that we think need transition plans, specifically as you change AB 1969 and turn that into SB 32, there are some issues with currently queued generators in there.

And our final bullet point is really around transmission impact. And I know this is a distribution presentation, but I think some level of transmission impact is okay, so we shouldn't necessarily focus on avoiding as much transmission impact as possible, we should let market mechanisms figure that out. It all boils down to time and money for a developer, as well as to a ratepayer, so if there's a market reason to site in a production-rich area, then the studies, the scoping meetings, and the interconnection will tell us what the benefits are, and we can make an economic determination. For us, we run sophisticated financial models to tell us what is the power price, and we focus on our lowest price projects because that's what we know is most competitive for utilities. There's a lot of developers out there, it's a very competitive market, it's a hard business, and we want to make sure that we're optimizing these projects so that the utilities will eventually pick us in their procurement mechanisms.

I don't know if we necessarily need to solve the transmission problems independently of some of the procurement items that are going on; rather, I believe it would be more efficient to let market mechanisms tell us that, and so if we're siting in an area with a lot of congestion, we're going to have a high network upgrade cost and probably four to five years or more to connect anyway, which means that we're not going to be competitive with that project. I think that's all. Thank you very much. I'm open to any questions.

COMMISSIONER PETERMAN: Thank you very much. I don't have any direct questions, but I am looking forward to hearing, if anyone from one of the utilities wants to respond to some of your recommendations, but as you noodle on that, I believe we have one more panelist on the phone, so let's turn to him.

MR. CODDINGTON: Can you hear me okay?

MS. KOROSEC: Yes, we can. Just let me know when you want me to change slides, Michael.

MR. CODDINGTON: Okay. There we go, great. If you want to put it on the second slide? Good afternoon, Chairman Weisenmiller and Commissioners Florio and

Peterman, and esteemed colleagues. Thank you for inviting me to give you a little bit of background on some of our research on this particular paper. And I'm looking at the clock here and I'm sorry I can't get us back on schedule, but I will try to get through this quickly and so I apologize for that. I just don't like to be late, so I may push it a little bit.

My work at NREL is primarily funded through the Department of Energy, although we do work with the CPUC and the California Energy Commission, as well.

Just a brief introduction of myself. I'm a Senior Electrical Engineer and a Principal Investigator at NREL, and I spent 20 years working at utilities, a big part of that as a Distribution Engineer, and I'm a Master Electrician and Licensed Contractor.

So bear with me on a couple of these slides. I threw those in here because -- for other presentations I've done very recently on this topic, I just wanted to point out with this that we saw over a gigawatt of PV installed in the U.S. this last year, which brought us up to just over 3 gigawatts, so we've got some real acceleration and issues to address -- if you want to go to the next slide, please.

I want to focus on the report, and I did bring in a number of other national experts from the Department of Energy, from Sandia National Labs, through the Electric Power Research Institute, EPRI, of which I think we've got Kristen Nicole on the phone, and she'll be doing a presentation in a little bit on another subject.

But we wrote this technical report, and it ended up being a big part of this FERC Petition not too many days later, but I'm just going to give you a little background on this report, if you could go to the next screen. Next slide, please.

And I just wanted to mention this, one back, well, you can pass through that, I was in Hawaii a few weeks ago and noted that the front page on the newspaper that there was a big brouhaha regarding this issue of 15 percent, and the Helco President really came under fire. Hawaii definitely has an interesting set of issues and pretty high penetration level, but it's a big issue over there as it is in California and other states. You can take it to the next slide, please.

So bear with me a little, I'm on remote here, so the goals of this report were really to, you know, obviously to help increase PV deployment levels, really to educate the stakeholders because there's a lot of misinformation out there by a number of people, and it's typically those that are not necessarily technically focused. So we try to educate everyone as best we can.

And we want to validate the concerns that you hear about maintaining reliability, safety, and cost. So those are important, I think we all agree with that.

We certainly have a goal of simplifying the interconnection process to help the utilities and their stakeholders, I mean, that's certainly one of our goals, and to do that would be to reduce approval time, potentially, and when you do that, hopefully we lower the interconnection costs. And the Department of Energy has got the SunShot Initiative Program and the goal is to see PV prices down to, you know, $2.00 a watt at the Residential installed cost, $1.50 a watt at the Commercial installations, and $1.00 a watt for Utility-scaled PV. So pretty significant goals, and if those goals are met, or even we come close to those, we're just going to see pressure to get more PV out on the system.

So why are we focusing on the 15 percent screen? Really, this directly relates to the level of deployment more than any of the other screens, and that's really the focus of this paper. But other screens are important, as well, and it's a complex landscape, but we really went after the 15 percent screen here; it shows up in the majority of interconnection procedures, and it's certainly perceived as a bottleneck for PV deployment, and it certainly may be, but it's perceived that way in many places.

One thing that many experts agree on, and some not, but it's definitely a limited metric, just the use of this penetration, a ratio of what that peak load is on a circuit, a line segment, during the year. It just, you know, you're looking back in the rear view mirror. Again, it's a very limited metric, that's why we went after it. Field experience, we found through case studies and other study, is that the rationale behind the 15 percent screen is certainly limited. Next slide, please.

So going back to the origin of the 15 percent screening criterion, I mean, you can go back and look at some of the Rule 21 information and, you know, this 15 percent rule of thumb was really meant as a catchall. And the problem with that catchall, it's hoping to catch any problem systems before they get on there, is it's a one-size-fits-all approach which certainly, when we've got higher penetration levels, one-size-fits-all is just not going to work.

So we looked at, you know, what we found with this, because of the limited rationale behind the screen of penetration, is that we can't just come up with a new solid formula very quickly, it's going to take some research. But we did come up with a number of short term solutions to at least be considered, and I know this one here has been talked about, I think that Dave Brown, and we talked about this, I think SMUD uses something very similar to this, and that is let's utilize -- if the information is available, and that's kind of a concern of some utilities, they may not have that minimum day time load data, but many utilities can get this information and there are ways to get it, and we realize that it may not be easy, but if you can use this minimum day time load during the solar peak between 10:00 and 2:00 p.m. for solar systems, that's going to give you certainly a better screen criteria. Next screen, please.

A second possibility would really be to apply some supplemental screens. If the system is a PV system and, let's say it fails the 15 percent or some similar screen to the penetration, is it a PV system? And we know that Inverter-based systems are certainly less problematic for the utilities.

And if we could have a quick voltage regulation screen that could be passed, same with the anti-Islanding, these may be good kind of, again, short term band aids for the situation. And we'll talk a little bit more about some of the longer term approaches.

One other thing that we suggest, and this is already being done in California, so this shouldn't be too much of a surprise, and we heard it from San Diego -- Ken just mentioned, you know, location, location, location, and that's exactly what this map really shows. The closer you are to the substation typically the more PV you can put in; but, conversely, that's typically where the homes and the loads are and you may not have room to put it in. And as you get further and further away from the substation, that may be where the land is available, but that's what we are suggesting here, that there may be zones of penetration that could help the utilities find more suitable locations. Next slide, please.

And for the Technical Considerations, I don't think this is a big surprise to anybody, certainly those that are technically the Engineers around, but the location of the PV vs. Substation, that's really important, the size of the conductor, and the line impedance at the PV system, the lower the better, and the presence of voltage regulating devices, you know, what other generation is on the circuit. Are you actually exporting power? I think we've heard, Dave mentioned, that if you can use the power where you're at, the problems seem to disappear and I'll talk a little bit more -- I've got a slide that mentions storage in a couple of slides here. But, again, presence and locations of loads and the type of loads are very important. Next slide.

So the case studies that we've done at NREL, and there's other organizations that have also done case studies, but they show that circuits can operate safely and reliably at higher levels of penetration. Each feeder is unique and it has different capabilities to serve both load and distributed generation, whatever that may be, if it's PV or other DG. We've seen feeders with penetration levels well over 70 percent, and they operate just fine, and the utilities claim no problems. But, conversely, if you've got a PV system or a distributed generation way out on a circuit, maybe miles from a Substation, the penetration level may be well below 10 percent and you can have significant problems. So penetration, again, is a very limited metric and that one-size-fits-all is just not acceptable. Next slide, please.

So Mid-Term, Long-Term Solutions. I mean, this is really where some of the research needs to go and I've got one slide after this that talks about what we're going to be looking at in California soon, but this first bullet is modeling, validating feeders with PV and other DG, and developing screening metrics and formulas that do have a good solid technical rationale, this is a major goal. The second bullet talks about larger conductors, adding voltage regulators, I mean, these are mitigation techniques, again, better communication. These aren't necessarily going to be the solutions we see, but certainly they may be parameters that change as time goes by. And advanced Inverter technology, you know, Inverters are changing significantly; again, those in the industry know that Inverters today can do so much more and, again, they're more advanced than they were just a few years ago and, again, are more utility-friendly. And, again, low cost storage solutions, batteries for free, if batteries were very low cost, which they're not, and they won't be, but I mean, if we could get the cost down, storage could be a great solution for the future.

And finally, the last slide, if you could. And I'm not going to go into this, but I think Kristen is going to talk about this for the CSI project that EPRI and NREL and Sandia National Labs, and several of the utilities in California are partnering on, and that really is to take a much harder look, you know, do some monitoring, some modeling, some screen development with some iterations, and come up with some more advanced technical screens and find better methods to increase penetration levels where they need to be without risking the safety reliability and cost of the circuit.

So, thank you for listening. I'm happy to answer any questions if you have any. I know we're way behind.

CHAIRMAN WEISENMILLER: Yeah, actually -- this is Chair Weisenmiller -- I guess the one question, last year we had a lot of discussion of advanced inverter technology, and also a lot of disagreement on the status. What's the precise status from your perspective?

MR. CODDINGTON: You know, a lot of the inverters available today, especially the larger more commercial industrial-size inverter, so inverters that are, say, 50 to 100 KW and larger, have the capability and the manufacturers are producing them so they have, say, the capability of providing a reactive power, which helps -- can help to mitigate voltage concerns, and they also have the capability, again, it's kind of an option right now because they're not standardized, it's one of the areas where we've got a lot of work to do, but they have voltage ride-through and frequency ride-through capabilities, or those are certainly capabilities that are options. But, again, we need good standards and that's where the IEEE 1547.8 comes in. Later this week, I'll be in New Jersey at the IEEE Headquarters, we're going to talk about IEEE 1547, and possibly opening that up for changes that would allow some of these advanced capabilities. So I hope that answered your question, Chairman.

CHAIRMAN WEISENMILLER: That helps. What about visibility? I mean, that's been the other issue, certainly and, again, we talked about it the last time, but how do we get better visibility without basically pricing everything out of existence, and then on the telemetry side?

MR. CODDINGTON: Visibility for the utility system? Is that --

CHAIRMAN WEISENMILLER: That's correct, I mean, so we can get some sense of what's going on and down the circuits as basically people see demand going up and down presumably as cloud cover, or whatever, goes over.

MR. CODDINGTON: Yeah, that's right. That's a great question. And certainly, with that kind of technology, there's always the cost issue, but NREL and some other partners have deployed -- and we partnered with SMUD and some other utilities in California and Hawaii -- we do have monitoring systems that are advanced high speed out on distribution systems, and we're learning a lot and that's part of the process is we're learning what we need to look for, and do we need one-second data, or is one-minute data adequate? The capabilities are there, it's a matter of what information do we need and what do we recommend? How can we roll that up into a tool that the utilities can use and just -- I think I heard the utility person, someone I respect very much, from California say, you know, "We want to put these systems out there, but we don't really want to have to babysit them. We want them to kind of run themselves." And so, as a national laboratory for the Department of Energy, I think that's one of our goals, as well, to help find ways to monitor these systems, but to take the monkey off the utility back and having to worry about them. That's a great question.

COMMISSIONER PETERMAN: Thank you very much, that was very interesting. I'm sorry we don't have more time to go into the details. I frankly don't know how we got so past time, everyone has been so interesting and quite brief, so thank you for that.

MS. KELLY: Okay, I want to thank the panel and thank everybody for coming and sharing your experiences. They have offered one minute to everybody to just go around quickly and make just one minute of comments about what you've heard, and the rest, of course, you can file in comments to this proceeding. So, Rachel? One minute.

MS. PETERSON: I'll just echo a theme that I think I spoke about, and then several other folks spoke about, as well. You know, our goal with the

Interconnection Tariff, but that the CPUC has jurisdiction over, is really to serve procurement, and procurement is really where the decisions about sending the correct market signals lie, and the correct market signals hopefully will begin to direct siting of DG into the more interconnection efficient places in the system. That's not to say they can't have transmission impacts or that a developer with a diversified portfolio can't handle a slightly more expensive and slightly less expensive project at the same time, but really our goal is to have the Interconnection Tariffs serve those other market-based mechanisms.

MS. KELLY: Dave Berndt from PG&E?

MR. BERNDT:  SCE.

MS. KELLY:  Oh, SCE, sorry.

MR. BERNDT:  Yeah, I haven't moved yet.  Hans, thank you for the fast, accurate, and fair discussion and those, too, are objectives.  I think finding that common ground is going to be the challenge.  I think, as managing each other's expectations around the interconnection customers, around when they have transmission dependent projects, and how that can be affected by what's happening in clusters and so forth is really, I think, going to be a challenge for how we come together on what is fast, accurate, and fair.  Hopefully the fairness has been reasonable as we look at an integrated queue and manage them accordingly, that's been kind of our mantra for the last couple years, and we'll come to find out -- you know, I look at what Midwest and kind of System operator is doing, changes in reforms they're doing, and there might be some interest there, but until then, we'll continue to research these as fast, accurate, and fair and work with you.

MS. WINN: Hi, Valerie Winn with PG&E. I think one of the takeaways that I have is that, even though we've done so much work in this area within the last year and a half, as we are implementing these policies, but getting to higher penetration levels, this whole process is going to need to continue because it's a very dynamic system, and how do we incorporate where we are and keep moving forward to find these fast, fair, equitable solutions, but still making sure that customer costs aren't going through the roof, and that we're able to reliably operate the system.

MR. PARKS: Ken Parks, San Diego Gas & Electric Company. We're really excited working with the Commission on the settlement with Rule 21, again, those rules laid out, and filing our WDAT SGIP Tariff, our reformed portion of it. But also, we're interested in working with the developers on our timeline, how to stream our timeline even faster, to help you to know what is a viable project that's out there, looking at the 15 percent penetration, and even to the point of the 1547.8 Inverter, maybe we'll get a Smart Inverter to help us out; we're excited about that.

MR. BROWN: Dave Brown, Sacramento Municipal Utility District. Well, I'm real excited about the report out from Rule 21, it sounds like a lot of good progress is being made, and having participated in the Rule 21 like 10 years ago, or whatever, we never thought that 15 percent thing would stick around this long. As a matter of fact, it was 20 percent when we first started. But what we're finding, and it was very encouraging, is that we're partnering with lots of developers and one of the things that really worked for us to weed out the players was a $20,000 MW application fee -- not sure that's always the best for everybody involved, but that got it down to a very manageable list for us and integrate -- now we're working with the same developers over and over and they've developed a level of expertise that they can meet our needs, we can meet their needs, it's more of a partnership than it has been in the past. Thank you.

MR. ISERN: Yeah, thank you. Just to reiterate what Dave just said, you know, we're all on the same side of the table here, developers need to get through the processes, the interconnection process, so that we can offer viable projects to the utility, you know, procurement and interconnection are linked now and I think that's really an accurate reflection of the world.

We're excited about some of the efforts underway. I think we do feel that there is room for additional improvement on top of that and we would love to play a part in that and really try to work with developers and utilities together.

MS. KELLY: Michael?

MR. CODDINGTON: Great, thank you. Well, we're excited. I think the project that you're going to hear about from Kristen, the California Solar Initiative Project, is really going to help pave the way to come up with some more customized screens, and when it makes sense to pass some of these applications through quickly, or maybe reduce the study time, we hope to help pave the way and hopefully make the jobs easier for the utility guys. Having done that job, it's no fun when you've got a big stack of applications, and to hear that there's -- and Dave Berndt said they've got 31,000 megawatts in their study queue, and to me that’s just astounding, that's about twice what Germany has up on their system, so pretty amazing. And we look forward to helping the

State of California solve these issues. Thank you.

MS. KELLY: Thanks again to the panel.

MS. KOROSEC: All right. Thank you, everyone. If we could have our next panel please come up and take your seats?

MS. MACDONALD: Good afternoon, Chairman Weisenmiller, Commissioner Peterman and Commissioner Florio. My name is Rachel MacDonald and I work in the Electricity Supply and Analysis Division, Electricity Analysis Office.

So this discussion builds on previous workshops and policy recommendations which identified a critical need for more information, more studies, more analysis, R&D, and the development of tools which will help us better understand the impacts of renewable generation, especially DG, at the distribution level. This information, in turn, will inform better interconnection and practices in integration of renewables.

And my panel is going to highlight current analysis in modeling projects that are underway, projects being developed, and proposed R&D. And my first panelist is Ron Davis, he's the Director of Transmission, Distribution, and Business Development for BW Engineering, and has been active in the studies of the impacts of high penetrations of renewable resources since early 2000. Ron.

MR. DAVIS: I want to thank you for the opportunity of coming here and speaking. I want to jump to slide 3 if I could and I'd like to start a little backwards.

I think it's important to kind of see where we came from, how we got started, and where we're at today. Back in 2001, I think 2002, maybe, the California Energy Commission should be commended for starting, I think, this whole analysis by looking at what was called the Strategic Value Analysis, which was later the Locational Value, which looked at transmission of mapping, where congestion was, and where renewable resources were, and doing overlays of where the benefits were of trying to do that in transmission. And then it went to the Intermittency Analysis Project, which tied the wind and solar together on that, and that's kind of the right hand portion of this slide, which says, you know, if we look at transmission and we look at resource planning, how the two tie together and how do we look at the value analysis.

After that, it was with the Utility Commission and their Self-Generation Incentive Program, where we took the methodology and said, "Can we apply it to the distribution grid?" So we can look at what value was existing PV, or any DG on the distribution system, how do we value it and compare it using the same methodology.

After that, it went to the analysis of looking at distribution planning and, with the high impacts of PV coming in on the distribution grid, how do we study it and how do we evaluate it. And that really came in two portions, one was a contract with Hawaii Utilities, the three main utilities in Hawaii, to begin studying the high impacts of PV on their distribution system, and also with the PUC/CSI RD&D1 solicitation, where we began working with SMUD and Hawaii on the impacts of high penetration on the PV systems. And most recently, we are working on the next solicitation, which is under RD&D 3 to continue the process.

So the concept here was, how do we tie all the models together? And our distribution planning has for a long time done unbalanced systems, so they looked at each individual phase, how do we tie that back to the transmission and to the resource planning area, and how do we tie in protection and operations into the same models and the same database so that everybody is modeling everything together, and how is everything working smoothly so that the analysis can be done on a consistent basis. And I'll get into it a little bit dealing with operations.

One of the big issues is, they have to change their switching routines. As you get more and more PV on, then you're doing your switching; when you switchover or switch back, you could have problems on your system that the system may not handle it, and there may be protection problems, relay problems, or other things with voltage and, also, for the protection to be able to look at the relay settings in the substation. So there is a need to have all common database in one system so you can switch everything back and forth. The other issue is, how do we aggregate a lot of single phase and three-phase Inverters out on the distribution grid to come up with a balanced system that you feed to the transmission system.

So the other work that we've been doing with SMUD and with Hawaii is to be able to tie all these models together, so you could have a transmission model that studies, in the case of Hawaii, it's 138 KV, their 46 KV, and their 12 KV, balance the system together, so now you could see the full impacts of what you have when you have distributed PV and larger transmission-based solar, along with wind, and how do you evaluate that all into a common database and be able to analyze it.

So one of the things we've been working on, and I heard a lot of interesting comments about the need to look at voltage regulation vars, frequency, modeling to be able to compare everything together, and so one of the things that we've been doing in Hawaii and SMUD is modeling each one of their distribution feeders in detail. And one of the issues up front that was brought up is the collection of data. There has historically been a lack of accurate data out on the field. Utilities have not been looking at a lot of PV penetration that's going to be out in the field, and what impact they have on the system. So you haven't been collecting it on a PV system.

Now, on a three-phase, a larger three-phase, you may put in SCADA, and you may be able to start collecting data, but what about all the single-phase PV that are out there. When you're talking in Hawaii, when they've got 40 percent penetration, 50-60 percent penetration, and most of that is residential, how do you know what they're doing? How do you know what impact you're having on voltage? And how do you measure their impact if you have a frequency disruption, and they start cascading off?

So these are the issues that we first had to solve and to work out when we were dealing with Hawaii. Same thing was true in working with SMUD. We had to look at where we want to put data, how do we look at where we want to put sensors out on a distribution circuit, and even into the substation to be able to collect power quality data. We needed a vars reactive power factor and, also, the tap changer operations for the substation transformers, and what the capacitor banks are doing on the system.

In Hawaii, we're finding, on some feeders, that they were operating at the minus 16 tap position, so they had no place to go. So when you have all this PV and you have a problem on the system, how are you going to operate? And what are you going to do? We also found there was a lot of maintenance problems that were going to be occurring because these tap changers were operating extensively.

There was a thing about SCADA and collecting data. A lot of times there's no way of getting this data. Sometimes you have to manually go out and get the data and read it, sometimes it comes in on a SCADA system, but it is in run format, so you have to re-do it, and so there's a lot of issues and it took us a lot of time in the RD&D3 and 1 and the Hawaii projects to begin how to collect all this data.

So right now, we're collecting 1 and 2 second data for both Hawaii and SMUD. Now, some people say, "Do we need all that?" Well, that's what we're determining. So you can imagine the size of our database, you can imagine the size of the work, but when we began to looking at under-frequency, and we looked at relay operations and with how the utility system is going to respond, some of the stuff is into the second iteration. So some of the issues and, as we look at this, how do we model the system in detail? And how do we find out where all these PV are? And how do we model where they're at? So the second map down below, it has all the green shaded areas, that's where all the PV was. So we had to model where all the PV was, and so we got all the addresses and had to come up with where they're located under GIS, and then assign them to the appropriate feeder. So we have this data, we're doing the runs, and we're doing this analysis, and one of the things that we're trying to do is, yes, there's this 15 percent rule, but we're trying to be proactive with SMUD and Hawaii in kind of saying, if we were proactive and be able to look at it, can we prescreen areas that are going to be a problem, and prescreen areas -- well, maybe we can let development go in, and we don't have to develop it, we won't have to worry about it for a while -- not everybody likes Hawaii because it's nice weather, I go there quite a bit -- and so we're studying these feeders that have a 40, 50, 60, I think there's even one that has 70 percent penetration. What problems have occurred? Can we take that information, bring it back to California and to other regions and begin explaining and showing what the problems are and what issues have to be done.

The next part comes in as to what we do going forward. So in the middle one where I talk about the bubbles, is we try to forecast where future development might be, and then how do we relate that back to the distribution feeder, so if you say, "I'm going to grow an area by 20 or 30 megawatts," how do I take that back and relate it back to the distribution grid? So working with Hawaii and working with SMUD, we're coming up with a Nodal Energy Forecasting methodology to try to apply that.

Then, the other step was, how do we look at clouds and environmental impacts on the DG operations? And we hear people talking about the minimum daytime peak and the maximum daytime peak, but in the summertime, it's always clear mostly here in California, so maybe your critical time is the fall, or the winter when you have a lot of clouds going over, and you have more variability, variability in your PV. That might become a more critical issue. In Hawaii, we're finding that the clouds are causing a lot of flicker, a lot of changes in the voltage of the operation of the DG, and when you have a trip on the system, we're finding that there could be voltage and frequency problems, and it will cascade. And there actually has been some brown-outs on some of the islands due to this flicker and cascading of outages.

In Hawaii, we looked at reducing on the three-phase inverters, going down to 57 Hz. You can't do that with the single phase. So there's a lot of issues and a lot of things to be able to look at, so the idea of what we're trying to do is put together a methodology and a procedure to begin looking at what is going to happen on the system, and how do we take that and apply it to other areas, so we're looking at a lot of things dealing with issues of study state, transient, harmonics, flicker, voltage, LTC operations, capacitor banks, battery storage, and how do all these play.

One of the outcomes we're looking at, it's not showing here, so we develop a matrix that says on each feeder, each substation or region, can I find out where I could potentially have a problem if I study all this, what is the mitigation measures that go to the next limitation, and can the utility price that? And as we go through, they can determine how much it's going to cost, is it cost-effective to continue to put PV on the system and be able to see until what point it becomes non-cost-effective to keep adding PV. We're testing a lot of models. I heard PG&E on their SIM (ph), we're testing three or four distribution models; one of the big issues we're finding is the distribution models lack the ability to model inverters in detail, and so on our RD&D3, PG&E is participating and we're going to be testing their model against some of the other models that we have.

I think one other big issue that people have to be aware of is gross and net load. When you have load and you're measuring feeder load, and there's already PV on there, that's not the true impact, the true load on a system, you've got to go back and correct for gross load, so that if the PV goes off, your system can respond and be able to handle the system on that. So we're doing a lot of work, we're looking at including energy storage, electric vehicles, energy efficiency, and demand response programs as we go through this to see what the impact is as we combine all these together.

And so we have a lot of work going on. We're tying back to the RD&D1 and RD&D3 as we go through this, and also doing a lot of studies. And one other thing is we're working with AWST on doing some PV energy forecasting and be able to come up with forecast across all the islands in Hawaii, and how to relate that back to the distribution model and then the transmission model.

MS. MACDONALD: Commissioners, questions?

COMMISSIONER PETERMAN: Thank you, Ron, glad to hear that you'll be bringing back some of the experiences you're having in Hawaii and helping form our process here, as well. So, thank you.

MS. MACDONALD: Next, we have Peter Evans. He's President of New Power Technologies and developer of a Power Network Management tool, *Energynet*®, which has achieved power grid visibility using existing Legacy utility data.

MR. EVANS: Thanks, Rachel. And thanks, Commissioners, for inviting us. We're actually not a studier, we're a tool developer, and so this project that I'm going to talk about is -- we're going to be implementing some tools to address some of these issues for the use of the CEC staff.

So, I heard a couple themes that I thought were really helpful, accuracy and speed is a great one and actually I think more accuracy leads to more speed, so grid impacts of DG are complicated and, so, one of our approaches is to get granular, get detailed, and get a clear view; so Rachel mentioned visibility, that's really what we're all about and that's what our approach is all about.

It's interesting here, I've mentioned what I think of as sort of the local or distribution impacts of distributed generation and none of them have direct --

they relate to penetration, but penetration isn't an impact. So these are things that can happen and that really should happen, so our approach has been to take a more detailed look at the individual projects with more granular view into the network and a more detailed view of the individual projects, but using software tools that allow us to do this very quickly.

So some of you have heard about the, I guess, somewhat infamous hobby project that we did where we actually looked at -- modeled a system, transmission and distribution comprising 250 feeders, looked at over 70,000 potential interconnection sites, and did power flow simulations equal to the depth of the preliminary and supplemental reviews in the new Rule 21 for almost 550 individual projects in a few weeks. So it can be done.

So now we're going to be looking at regional impacts of real projects, rather than screening through hypothetical projects and this, to me, is in some ways a lot more interesting. And so the question is how might a large number of projects with very high level of penetration relative to load impact a regional transmission system, so it's not just the individual project impacts, but also the aggregate projects? But every project is unique and the impact and aggregate is the aggregation of the individual projects, so we need a deep view and/or a wide view. Next slide.

This is -- we actually literally just started this project, but this is a look at the San Joaquin Valley and I apologize for the pushpins, but they show you where the substations are and sort of generally define the area that we're going to be looking at. This area is served by 230 kV transmission system under the jurisdiction of CAISO, in general kind of the Mendota, Helms, Schindler, Gates, Kingsburg, Arco area, but then we're going to dig down into that, into the 230 system and the 70 kV network sub-transmission system, and then individual feeders, 52 individual feeders served from 18 individual substations and there's 47 queued projects that I've identified representing 515 megawatts of load of generation, which exceeds the load that served in this area. So if all those projects were built, it's going to move the transmission flows. Now, that's not to say they all will be built, but we're going to pretend like they all will and to look at a system as if they were all there. Next slide.

This is -- I'm sorry, these are pretty tough to see, but this is kind of zooming in, you can see an area -- this is Avenal and there's a number of projects that are right around that city that are in the queue, and then if you go to the next slide, this is looking in, again, Avenal Substation, and the blue line is the circuit that serves this area, which we've modeled, and then it happens that there are a couple projects there already you can see them, and if you like real projects and real numbers, based on my handy metric that I got from the Energy Commission for megawatts per acre, the one at the top is a 6.2 megawatt project, the middle one is a 17.5 megawatt project, and then that's a 24.3 megawatt project at the bottom. There's about 50 to 70 megawatts in the queue at this substation, and the total serve load at the substation is less than 10, or around 10. And this is one of -- what did I say? Sixteen substations? So it's going to be a pretty interesting project and hopefully we'll see some interesting impacts that we can come back and talk to you about.

So our approach and the tool developed to use this will allow us to look at the impacts of these projects individually, but also in aggregate, across this transmission system. We'll be able to look at -- because we can see the direct impacts, we can look at "what if" scenarios and also N-1 contingency conditions.

And then the good news with a model like this is that it leverages existing resources and infrastructure, so it's built on Legacy utility data, it's developed with software, so it can be updated every day if you wanted to develop new maps and new models, you could crank those out daily if you wanted to. And then we could, and can, and have tied in the existing SCADA for validation, that's not part of the scope of this particular project, but we could if we wanted to.

So I expect that we're going to be looking in existing conditions, are there low voltage areas where DG projects may be prone to tripping. We'll look at state impacts of all this DG penetration, things like loading and voltage rise within the transmission system, and within the individual circuits. I think we're going to look at impacts on contingency scenarios because this is something that the CEC staff has asked us about, and do the contingency scenarios that they're using for looking at the transmission system change with all this generation.

We can look at DG event-related scenarios like ramp-up in the morning, ramp-down at night, and then also things like coincident output change, like what would happen if all the DG dropped off at once, or if a share of the DG dropped off at once, due to a passing cloud, or a voltage upset. We can look at them on a steady state basis and also what I would call a quasi-dynamic basis, which would be like less than a minute impacts before the system can respond. And then we could also look at some of the things that they're talking about in 1547.8 like, you know, what's the impact of lack of low voltage ride-through? If you lose all the PV, does it make it difficult to operate the system in a very short timeframe?

So that's all I was going to say about that, but I'll answer questions.

MS. MACDONALD: Thank you, Peter.

COMMISSIONER PETERMAN: I just want -- I had a clarifying question. So the analysis, the simulation will be using proposed, but not yet built DG projects?

MR. EVANS: Actually, I think some in the queue are actually built. But, yes.

COMMISSIONER PETERMAN: And when do you expect the initial work to be completed?

MR. EVANS: So we should have preliminary results in July.

COMMISSIONER PETERMAN: Great. Thank you.

MS. MACDONALD: Thank you. Next, we have Dr. Alexandra "Sascha" Von Meier. She is the Co-Director of the Electric Grid Research Program at the California Institute for Energy and Environment. Her research focuses on power distribution systems, Smart Grid issues, and the integration of distributed and intermittent generation.

COMMISSIONER PETERMAN: I just have to say, before Dr. Von Meier speaks, that if you are in the market for an excellent electric power systems textbook, get this woman's because I had an early version in Graduate School and it was a lifesaver, and so especially good for a non-Engineer.

DR. VON MEIER: Thank you, Commissioner. Thank you so much and thank you, Rachel. It is my pleasure to speak to a project that was just approved in last week's business meeting, a PIER funded project which CIEE has been working with our utility partners to articulate and the utilities that we look forward to working with in the future on this project include the three IOUs, as well as the Sacramento Municipal Utilities District.

Let me step back and review the goals of this Distribution Monitoring for Renewables Integration project. As was detailed in the previous panel, it's important that we're able to make smart decisions about interconnecting distributed generation, also timely and precise decisions. But in the event that upgrades to the distribution infrastructure turn out to be necessary to accommodate our policy goals for distributed generation without compromising safety and reliability, we also want to be smart in our decisions about those upgrades. And finally, we want to be able to look into the future and predict future impacts, both with higher levels of penetration and newer technologies such as some of the Advance Inverters. So for all these reasons, we need more data. We need empirical data of what is actually happening on distribution circuits, which historically for utilities it didn't make sense to collect data with the kind of granularity that it turns out we need today.

So in this project, to essentially gather intelligence from the field about what is happening on distribution circuits as distributed generation is being added, I think, I'd like to emphasize the term "collaborative" because, really, as was pointed out, no two distribution feeders are alike, there is great variation among distribution circuits, between and among utilities, but also within each utility they have many different types of distribution feeders. And so we need to really leverage all the data that we can get to make informed decisions and to try and really see where can we generalize, and what can we learn from having a statistically significant dataset about how these circuits behave.

The first phase of this project is really to bring data together to analyze and study and observe these behaviors from instrumentation that's already out there in the field. As Ron Davis pointed out, sometimes there are difficulties not just with the instrumentation in the field, but in the collection process of the data, it's really the back office process that sometimes is difficult to make use of all the information that may be physically accessible in the field, so the first phase of this project is to bring together what measurements we can, and really study it very carefully.

In the second phase, that we hope will come into being over the coming years, we're looking at hopefully adding, based on what gaps we identify and what utilities identify are there in the measurements, we looked forward to adding more sensitive sensing and monitoring equipment that takes very rapid detailed samples of such quantities as voltage and current flows, and that does so -- the slide says "sub-cycle sampling rates," meaning it's looking at it more than 60 times a second, which might sound like overkill, but my second slide will speak to that.

I'm actually not ready for that slide yet, but thank you. Let me say first off that, understandably for the utilities, it's easier to justify installing instrumentation on circuits where they already expect to be seeing problems, but in the interest of science, it's actually very important to also look at data from circuits that don't yet have high levels of DG, so that we can look at what changes are occurring as a result of those installations. So we want to be able to compare impacts of different sizes and locations of DG on such things as voltage profiles, but also protection systems. We want to be able to get baselines for how distribution circuits are behaving before the DG goes in, so that we can then compare going forward what are the impacts.

As I said, we'd like to be able to make intelligent generalizations, so rather than having to study each individual feeder in detail, there have been some efforts, one in the CSI Initiative, another important effort by Pacific Northwest National Laboratory, to attempt a taxonomy or a typology of feeders so that you can say, out of the many thousands of circuits, are there some basic ordering categories that you can put them into in order to make certain decisions, maybe not all decisions, but to simplify this process somewhat. And again, if you want to do such characterization well, you need empirical field data to support that. What we also look forward to doing this -- also was spoke to earlier -- is to validate models of distribution circuits which, of course, the models are what engineers use to predict what will happen; as we add certain new components, we want to be able to anticipate the behavior, but the model can only be as good as we are sure that it in fact is consistent with the physical measurements, so the validation is an ongoing process, especially as we're encountering situations that couldn't previously be validated because they didn't exist, we didn't have the circuits before with so much solar generation, for instance. So there are also new components that need to be newly modeled and, finally, a really important part of doing good science is knowing, well, how carefully do you have to look. And that's where this sort of approach for over-sampling comes in.

What I like to think of as a future Phase III of this is really routine monitoring that the utilities do going forward, that's going to be necessary as DG becomes an everyday occurrence, and yet I think there will always be a need to look at what are the implications of additional installations and there will have to be increased monitoring in the future. But at the same time, the utilities and ratepayers, we all want to do that in an intelligent way, we want to measure what we need to measure.

So to that, now we get to the next slide, and Tom Bialek of San Diego Gas & Electric prepared these graphs and I love these graphs, which is why I'm borrowing them, they illustrate this question of, well, how closely do we have to look? And what sorts of things do we expect to see? So this first graph shows power injection from a photovoltaic array toward the end of the distribution feeder over the course of three hours. And this profile looks really quite boring, and you might say, "Well, there's nothing to it," but if you look with a somewhat greater resolution, and if we advance the slide, we see 15-minute data, so that's a very different story that we see if we sample the measurement at these closer intervals. And 15 minutes, as you know, is sort of the standard time interval of Smart Meters. So we might say, "Well, 15-minute data, is that the standard for knowing what's happening on the circuit?" In this instance, they decided to look a little more closely because this was a circuit that they had some concerns over what the impacts of the system may be, and it turns out, if we advance again, we see, well, if you sample at five minutes, you see yet a different behavior and, in particular, you're seeing some very steep ramp rates, which may or may not cause problematic impacts on voltage on this feeder, it may or may not adversely affect some of the loads on this feeder, but this is something that you would like to know and that you would have missed had you only sampled at the 15-minute intervals. And, in fact, advancing once more, it turns out at the one-second level, you see yet a different behavior, and you wouldn't have known that this behavior is occurring unless you had looked. So that's why we've proposed, and the utilities, engineers we've worked with, are I think in very good agreement that there is a value to doing some over-sampling initially to see, well, how closely do you have to study these circuits, and under what circumstances, to then be able to back off and say, "Well, you know what? There's really nothing interesting happening at the one-second level, or the one cycle level, so therefore in the future, in these types of instances, we could sample at longer intervals."

But, so this is a project that I think will work very well in conjunction with other related projects that are underway and, you know, let me iterate personally, I think the sharing of this information is really crucial to the process here because we're essentially all learning together about things that simply we didn't know before, and in a sense, having studied the subject for over 20 years at a time when grid connected photovoltaics were still a great oddity, in a sense, I think these are difficult engineering problems, but they're good problems to have. Questions?

COMMISSIONER PETERMAN: No, I think we're just still recovering from your drafts. We weren't sure what you were going to unveil next. No, that was very interesting. We're looking forward to the results of your study. Thank you.

CHAIRMAN WEISENMILLER: This question is probably more on the Hawaii side, of whether you've seen similar variation as you go to the smaller timescales?

MR. DAVIS: Yes, we have. In fact, that's why we're collecting the one-second, and we're finding that, when the peak PV is coming on during the day, it has variations like this. And then you look at the evening ramp, that the units can't ramp up quick enough to be able to respond to when PV goes off, and the system is going into an evening peak, that there begins to be voltage problems and other issues on that system. So we're actually simulating that currently in the models.

COMMISSIONER PETERMAN: Actually, I do have a follow-up question for Dr. Von Meier. So, is it right that you would have multiple PV arrays feeding into the same distribution feeder?

DR. VON MEIER: That is often the case, yes.

COMMISSIONER PETERMAN: So would it be possible, then, that you could have multiple ones that would have slightly different patterns that, on aggregate, would keep loads similar? I'm just wondering if there was some geographic diversity we can exploit.

DR. VON MEIER: That's actually a very good question and there's research underway studying precisely that. Researchers are looking at how far away do you need to be in order for the diversity, for instance, passing clouds, the clouds are only so big, so the farther away they are, the more you tend to have cancellation. Also, it seems that these very rapid short-term variations are more likely to be canceled out. Then, again, if the DG -- if the PV arrays are spaced farther apart, then some of the customers on that circuit may not get the benefit of all the cancellations, yet, so you may get voltage profiles that still vary somewhat erratically, and it remains to be seen what is a problem and what isn't.

MS. MACDONALD: Thank you, Sascha. Next, we have Jamie Patterson from the Public Interest Energy Research Program. He's a Senior Electrical Engineer.

COMMISSIONER PETERMAN: Which is at the Energy Commission --

MS. MACDONALD: Which is at the Energy Commission.

COMMISSIONER PETERMAN: -- just in case you didn't know.

MS. MACDONALD: It's our R&D Program.

MR. PATTERSON: Yes, I work in the Research and

Development Division here. Actually, it's down on Fifth Street, but close. I hope you will please bear with me, I'm recovering from a little bit of a cold here today. Anyway, next slide.

What we do is within the PIER Program we fund quite a little bit of research among the various areas which we have been talking about today, but what we're looking at is we tend to try and look at things from a Systems approach, in my particular focus area. And what we're looking at is, the thing about connecting renewables, or any of these other things to the grid, such as electric vehicles, or any of the other new types of technology that are out there, if we are kind of where we were at the turn of the Century, originally when they put out electricity, it was primarily for lighting. Then, later on, they developed appliances, and the question came up, "How do we hook those up?" And if you go over to the State Capitol, you can see the adding machine where they took an extension cord and they literally screwed them into those Edison basins up in the chandeliers, and made them work.

Well, today we have a similar problem. We need to connect renewables, electric vehicles, demand response, and a lot of other things up to the grid to create -- and we think the secret of that is to simply make a smarter grid, go to a smart grid. So we're doing a lot of research to try and bring a smarter grid to enable greater renewable connections, get greater renewables.

We've done a fair amount of research in the areas of -- on this slide, you can see that we have a number of typical, what we consider to be typical Smart Grid technologies and we've done quite a lot of research in the year that PIER has existed as a program in these areas. We, for example, in the areas of modeling, which I'll start to focus on here, we funded Peter Evans on his developing his Energy Net Methodology, yes. And -- it's now at the application level and it's doing some good returns now on that investment. We're currently funding Sascha on the distribution, she is working with PG&E on a volt var project. We have a lot of synergies among our projects when we put those together. And PG&E is basically looking at -- they're kind of working hand-in-hand, they're going a big modeling project using more traditional tools where they're going to be looking at, say, smart inverters and their impacts on the grid and characterization. So all of the research is going hand-in-hand.

On San Diego Gas & Electric, we're looking at some storage projects. One of the things about renewable interconnection, people talked about storage being the answer, but it's expensive and costs a fortune. So one of the ways that we might break that price down would be to simply lower the size of energy storage needed and, with my power factor correction, which is also maybe a little too esoteric, I guess, for me to bring up right now, but if you take and you fix it at the source, it's generally cheaper to fix things at the source than it is sometimes at the head end, so to speak. So we're looking with San Diego Gas & Electric to see if it's better to have small amounts of energy storage on the 240 volt side of the distribution system vs. large amounts of energy storage maybe at the substation level, and that's something that is pretty basic, it seems, but good research we're doing.

We also do a little bit of forecasting. I mean, actually we do quite a little bit of forecasting research. We have, well, over half a dozen different forecasting things, and it's not just long term forecasting for renewables. We are looking at the short term forecasting. We're working with UCSD and using their Sky Tracker Camera to see if the clouds can be -- and we're looking at like, you know, 15 minutes -- the Sky Tracker Cam looks out at the horizon and see if a cloud is coming, and basically can tell you whether or not you're going to be shaded with about 10 to 15 minutes of warning, and about how long that will last, and hopefully that will help with some of those intermittent ramp rates that we saw on Sascha's slide. So we're actually doing quite a number of different things. Next slide.

So one of the things we're doing that we're going to be looking at towards the future, in addition to some of the ongoing work we have, we're going to be continuing to try and understand the impacts of increasing PV capacity through Sascha's work through the work done at PG&E, and also PG&E's work, by the way, all this work is overseen by a technical advisory committee made up of all the utilities, okay, so that way we can share our knowledge and share our experiences. Southern California Edison, for example, have done some extensive modeling work using Smart Inverters and I understand that they will be contributing some of that to PG&E's efforts in the volt var modeling project.

But one of the things that we have come to, when we were setting up these programs, what came to mind as a team lead in this area, is that many of the modeling -- many of the modeling tools out there don't really take a systems approach, they don't look at the overall distribution grid, say, as a circuit. And we're concerned about that because it's difficult, as microgrids get out there on the system, it's difficult for people who want to install microgrids to actually model them accurately and see how they will operate in practice. So what we're looking at, if we're thinking about doing a new initiative on modeling work where we're going to be looking at some of the new tools such as Grid Lab D, sort of a -- I believe it's a -- what do they call that? It's an open source -- I believe it's an open source product that is available from one of the National Labs, and we think that might have promise, as well as other tools that are commercially available. Okay? So we'll be looking out for those types of tools, trying to see what their characteristics are, see if perhaps maybe they can be expanded through the use of module programming to provide us with greater information about how the grid and our distribution system can operate with more renewables on it, and give us greater insights into that, so maybe that way we can get past the rules of thumb on the 15 percent barrier.

The other thing is, of course, if we're also looking at how we can take and maximize the capacity, as always, because we are big promoters of renewable energy, I know that even some of the -- we've heard today from some of the other people that some of the large Inverters have the ability to do volt var control, but I know that I have seen some studies showing that some of the small micro inverters, I don't know if I want to name names here, but I know that one of the companies that is over in Santa Rosa, for example, that makes these small micro inverters, has said that they have volt var capability on those, and they see that as the future. Okay?

Now, volt var capability -- and I have seen presentations where that might be able to increase the capacity for photovoltaics by as much as 100 percent on our distribution feeders, and here at the Energy Commission in our research and development, we think that that would be a good thing.

With that, next slide, please. In research, we always try to see what is needed and then do research to respond to that. And we like to be proactive because I can't wait until 2020 to do research to solve the problems that 2020 brings. I have to do it now so that the solutions are available now. So if anybody knows what grid changes are needed to affect greater interconnection, or what research needs to be done, I would encourage them to contact me, Jamie Patterson, over in the Research and Development Division of the California Energy Commission. Thank you.

COMMISSIONER PETERMAN: Thanks, Jamie. And I would also ask, if anyone has a suggestion in that area, to submit it as public comment to our record, or at least let the IEPR staff know about it. Do you have any comments? Okay. And before we turn to Craig Lewis, just so everyone can plan their time accordingly, we try to respect the time we allot for public comment in case people are waiting for that period, so we will stop for public comment regardless of where we are at 4:30 and take any there, and then wrap up with the panel as much as they are willing to with questions and discussion amongst them. And I will just give advance notice, so far I only have two people noted for public comment and one of them is you, Craig, so I would just ask if you would put your public comments into your statement. And if you are interested in public comment, please provide a blue card to Suzanne or contacts on the phone. Rachel?

MS. MACDONALD: I would almost suggest, then, respectfully, we have Kristen Nicole on the phone from EPRI, so if Craig is going to segue into public comment, maybe let's go ahead and start with the EPRI speaker next and then wrap up this panel with Craig.

COMMISSIONER PETERMAN: Or, we could just -- Craig and then we can -- it's not so much a segue so much as I thought he was the last panelist, and I didn't realize --

MR. LEWIS: I'll be brief.

COMMISSIONER PETERMAN: I didn't see on the agenda the last one, so my apologies. We'll just have her afterwards.

MS. NICOLE: Can you guys hear me?

COMMISSIONER PETERMAN: We're going to do five minutes of comments from Craig and then five minutes of comments from our panelist on the phone before we do the break.

MS. MACDONALD: Okay.

CHAIRMAN WEISENMILLER: We just wanted to make sure that, since we said public comment from 4:30 to 4:45, that we actually get that scheduled.

MR. LEWIS: And I actually have a presentation, I'm on the panel, so it's not for public comment.

MS. MACDONALD: Yes. We have Craig Lewis from the Clean Coalition. He is the Executive Director of the Clean Coalition and he is going to be telling us about a project that they're proposing, an initiative that is under development right now to look at a lot of the interconnection issues and integration issues with renewables.

MR. LEWIS: So, Chair Weisenmiller, Commissioner Peterman, Commissioner Florio, pleasure to be here with you. The Clean Coalition is a non-profit organization that is focused on transitioning the United States to a Smart Energy future and our goal is to do that in a cost-effective, timely, and environmentally sensitive fashion. The history of the Clean Coalition has been primarily focused on removing barriers and adding transparency for procurement and interconnection processes, and as we've had a significant amount of success with that with some of our Clean Local Energy Accessible Now Programs, what are called "Clean Programs," we just launched a Clean Program with Palo Alto, California, we've got another one coming July 1 that will launch officially on July 1 in Long Island, New York, and another coming in Fort Collins, Colorado, we've got these Clean Programs really happening out there, and those are to remove the barriers to procurement and interconnection.

And these utilities that are implementing these clean programs are now starting to ask what happens when we get to penetration levels of clean local energy that are above 10, 15, 20 percent on a distribution grid. Well, in order to help make sure that nobody has to panic, the sky is not going to fall down just because we get to 25 percent penetration levels of clean local energy, the Clean Coalition has embarked on a project with five utilities, we're going to deploy clean local energy at penetration levels that are 25 percent or greater on a single substation for each of those utilities, and we will balance as needed with energy storage, potentially with demand response, and potentially with curtailment.

So this picture shows a very simplified view of a distribution grid, everything in the red polygon is part of the distribution grid. And the Clean Coalition has long been the leading advocate for wholesale distributed generation which is where the generation is interconnected directly to the distribution grid, it's not connected to the transmission grid, and it is not connected behind the meter.

And the benefit of wholesale DG is that CAISO and everybody else that needs to see the energy generation can see it, you don't have all the limitations around net metering and whatnot, and you don't have to -- the sale is directly to the utility, so you can get this in larger quantities and you can get it very cost-effectively.

So the project that we have going is to take a single substation with five different utilities and add enough wholesale distributed generation such that we will get to at least 25 percent of the total load on that substation coming from the wholesale distributed generation.

If you go to the next slide, we have been looking to design basically a standard deployment that we can do at all five of these utilities and the standard deployment will be heavily weighted on solar for the wholesale distributed generation, and we will use planning tools on the distribution grid; and the reason that I'm very excited to be here on this panel is that the toolsets that are available for the distribution grid have matured significantly. And we found a company called Gridiant that provides a tremendous capability for not only modeling the existing grid, but for simulating the grid that you might want. In other words, you can deploy, you can put in your distributed generation, you can put in your energy storage, you can put in your demand response and curtailment, and you can see exactly what that grid is going to do, and you can see it over time. And what this allows, if you recall back from this morning's panel, they talked a lot about the transmission planning process, and then they talked about, for distribution grid, there is no distribution planning process; the distribution planning process is you look at every single process you want to interconnect to the distribution grid and then you kind of do a power flow on that one project and see how it impacts the grid. Well, this is completely backwards to how it should be working; we all know where the loads are, and the closer those loads that you actually provide the generation, the more value you're providing to the ratepayer, as long as you're getting the same overall cost and avoiding transmission, is a huge ratepayer savings. There's a lot of extra savings in there that can be applied to these Smart Grid solutions.

In the case of Palo Alto, they found that the transmission-related costs of their clean program when they're providing wholesale DG, is over $.3 KWH. So that is a lot of extra head room to pay for the intelligent grid solutions and the distributed generation.

What this particular screen shot shows is that there is different value, depending on where you interconnection your generation on the distribution grid. This particular shot is four separate substations that are served by eight feeders, and the color coding basically shows you at the transformer level the transformers serving multiple customers -- and each transformer is a little circle there -- at the transformer level, the color coding tells you what the value of distributed generation would be at that point. And in this case, the red has the highest value. And in the table on the left, it shows that if you put a megawatt at the very top of the table there -- it says 1.0093 -- that says if you put a solar power project of one megawatt in size in one of those red zones, it's equivalent in value to 1.36 megawatts of solar that would be hitting the substation, so you're essentially getting a 36 percent value boost by putting that solar where it is really needed, and you can do the same type of modeling with demand response, energy storage, you can do it with curtailment, rather than building out something, building out more infrastructure, you can essentially just curtail your generation and save yourself a whole bunch of capital expenditures. Next slide, please.

And what I want to point out on this particular slide is that this same type of modeling allows policy makers in California, and anywhere, to make sure that the tremendous level of investment that is going into the distribution grid year after year is being made in the most sensible fashion possible. Right now, we're talking about a very opaque process where the utilities get to spend billions of dollars a year upgrading the distribution grid year after year after year, and there's very little accountability to how that money is spent, there's very little transparency upfront about how they're going to spend that money, and tools like this allow California policymakers to make sure that the utilities can be spending that money in a very intelligent fashion, that they're going to be doing the upgrades at the places that they are needed.

So what is shown here in this particular chart is, where you have the red dots, that is where your transformers are about to break. That tells you exactly where you need to go invest in transformer upgrades. And you can overlay -- there are a lot more slides, but I was told I only had two content slides, so this is my second -- you can overlay this slide with the prior slide, and you can see where not only do I need to go change out a transformer or two for relatively low cost, but where you can do that *and* accommodate a boatload of additional distributed generation where it is really needed on the grid. And that concludes my comments. Thank you.

COMMISSIONER PETERMAN: Great. Thank you, Craig. So can you share with us who the five utilities you're working with are? Is that --

MR. LEWIS: We have not publicly disclosed the exact utilities, but I can tell you this, one is in California, one is outside of California, and we've got three -- we've got a number of additional utilities we're talking to. So we've got two relationships that have been locked down, and we've got a number that are under discussion. But our goal as an organization is to have five utilities, that we plan what we call a "Distributed Generation Plus Intelligent Grid Deployment," and the planning will be done by the end of this year in all five locations, with the intention that the deployment will happen by the end of 2013.

COMMISSIONER PETERMAN: Great. Thank you. So, Rachel, what do you think? Do you think we should take the public comment quickly now? We have one so far, and then we can go to the presentation? Let's start, let's just see what public comment we have now, if you don't mind, and then we'll go to the next presentation.

MS. MACDONALD: Thank you. Kristen, hang in there.

COMMISSIONER PETERMAN: Because I also don't want to cut her off. We have Julia Prochnike?

MS. KOROSEC: Actually, she had to leave because she had to catch a train at 4:40, so she wasn't able to stay for the public comment period. We don't have anybody online who wanted to make a comment. Is there anyone in the room who wanted to say anything?

COMMISSIONER PETERMAN: Well, there we go. We'll open it up again once we're done with the presentations and the final conversation amongst the panelists, but I did want to provide that opportunity.

MS. MACDONALD: Thank you. Last on our panel is Kristen Nicole from EPRI. She is a Senior Project Engineer at the Electric Power Research Institute, EPRI, and she is focusing on Power Systems Integration for Variable Generation.

MS. KOROSEC: Kristen, your line is open.

MS. NICOLE: Okay, can you hear me?

MS. KOROSEC: Yes, we can.

MS. MACDONALD: Yes.

MS. NICOLE: Okay, great. Oh, fantastic. Well, I'm on the East Coast here, so I'm going to reserve all these comments as my public comments, but I wanted to just thank you guys for your time and for sticking with me in the last -- throughout the entire day and kind of waiting to hear this presentation. As Mike said, there's a lot of activities that are going on right now, but I really do just want to thank you for the opportunity to speak, Commissioner Peterman, Chairman Weisenmiller, and Commissioner Florio.

Like Rachel said, I'm with the Electric Power Research Institute. I'm actually based in D.C. I'm sure that most of you guys are familiar with EPRI through our work in Palo Alto and Knoxville and Charlotte. We're a nonprofit organization funded primarily by the Electric Power Systems industry, both in the U.S. and internationally. And I do want to just state that we are this year celebrating our 40th anniversary and so there's a lot of activities going on in memory of Chauncey Starr, our founder and kind of mission leader, so it's been an exciting year.

But I do just want to start out and talk briefly. I was also recommended to only have two content slides, so I'll try to keep it short for everyone. But I do want to start out to give context to what we're doing and why. What I'm trying to present on actually spans mainly our Power Delivery and Utilization Group, where there are hundreds of employees that are working on this effort, however, our approach to monitoring really started in the '90s out of Knoxville with our Power Quality Group. And we had a project called Distribution Power Quality Project, and we had 277 distribution sites throughout the United States where we were able to get frequency and power quality events. And then, later on, in the early 2000's, we had the DPQQ project, which really looked at characterizing power quality in terms of short duration variation such as voltage sags, voltage swells, and interruptions.

And so that work and all of the data that came out of that work really is what folks were looking to do with solar as distributed generations come on line. And so, in light of that, you know, we had thousands of days of coverage where we're collecting all this data, and it's actually set studies for years now, but in light of that, we started the Distributed PV Monitoring Project in 2010. As folks have mentioned, there's a high penetration of distributed energy resources coming on line and the utilities need to change operations and planning methodologies in order to accommodate the DG, you know, the system was designed for one-way power flows. So we're really talking about a transition in power systems operations that have really never been embarked on before. So it's a big challenge, but we have a lot of folks within EPRI and within the National Labs, like Mike Coddington mentioned, that we're working with, and Sascha and other folks who are also trying to tackle a lot of these problems, so it's a pretty exciting time to be working on these issues.

The DPV project is, really, we saw a need in the electric utility industry for high resolution, time synchronized data to understand the feasibility of PV systems, and so we're collecting about 200 to 300 -- well, we have over 100 sites right now, clustered predominantly in the southeast and west coast regions. The data collection started in 2010 in December and we are trying to get up to about 200 to 300 locations nationwide. We're coupling these monitoring systems with new and existing PV systems, some of them are just pole mounted standalone systems. The datasets that we're collecting from the systems include PV system, AC output or radiance measurements, and then what we're doing is we're actually feeding those datasets into our power system studies activities, so I'll talk about that a little bit later.

The actual systems are -- we have actually about 20 utilities that are participating right now, we're in 26 cities around the country. The timeframe is about 18 months. Again, we're collecting AC output, radiance, temperature, humidity, wind speeds, DC voltage and current and back temperature, let me see here, excuse me, so we're also doing humidity, wind and rain, I didn't mention those. So we're collecting all of these data points and all the field data, then, is transmitted back to EPRI on a periodic basis. A little bit of fuzz on the line right now, and I'm not sure if that’s (inaudible) -- can you --

MS. KOROSEC: We can still hear you, Kristin.

MS. NICOLE: You can still hear me, okay. So anyway, again, it's one-second resolution time sync data with automatic data transfers and remote log-ins. So we're using this data for a host of different research activities.

One thing that -- the last time I gave this presentation, I forgot to add in the importance of -- excuse me -- line crew O&M and installation activities that are going on. Georgia Power wrote an article in *T&D World* in February talking about the lessons learned from participating in this project and, so, I do want to make sure that we're not taking away from, you know, obviously it's important to have -- there's a need for data, we're solving that need, but it's also important to understand that the line crews and folks who may not be working with this technology on a day-to-day basis are able to also gather some lessons learned and, so, we're collecting that data, as well, for monitoring techniques and lessons learned, which we're sharing with the utilities around the country. So I do feel like that's an important part of the project that sometimes gets left off.

But anyway, we are looking at ramp rates at 10-second, 1-minute intervals and, again, I think a lot of folks have seen the variability data and know that the activities when you have clouds coming over, or other things that can cause ramp rates, and so we are looking at those in detail and, frankly, really what we're trying to do is, like folks have been saying, is translate those ramp rates into power quality events on the system. So that was my one slide; if we could just go to the next slide.

We are using OpenDSS as our modeling, it's also an open source software platform compared to GridLAB-d is another one that I believe Jamie mentioned earlier, so EPRI fully endorses OpenDSS and I would happily refer you to Roger Dugan or Jeff Smith, or other folks on my team who are gurus in this tool, you know, because it's an open source tool, similar with GridLAB-d, we don't have the kind of consulting team like you would with Synergy or some of these other commercial software products. And so, you know, that's one of the disadvantages in using open source software. However, there are certain elements within our tools that are used more for research purposes, which can then be adopted into some of the commercial software applications. So we do feel that the tool, you know, we've been using it since 1997 for a variety of different activities, including the detailed distribution system analysis and aggregating up into some of the full system issues, and so it's actually been a pretty positive experience working with the monitoring data and then also with the tool.

Just briefly, for some of the feeder modeling activities that we're doing, we've looked at hundreds of feeders around the country, but like Mike Coddington said, we're paying special attention to circuits that have high penetration on them, obviously, because those are where you're going to have more of your power quality events; and then, also making sure that all of the efforts that we're doing are feeding into 1547 IEEE's Codes and Standards, and the FERC Interconnection recommendations and 15 percent limits that Mike was talking about earlier.

I do kind of want to take a break before I talk about the project, briefly, and just mention that we are planning a workshop at IEEE Power and Energy Society -- excuse me, not "we," but NREL is planning a workshop on July 26th, it's a Scripps forum at UCSD, and really what this workshop is intended to do is look at that gap -- not gap, but kind of mismatch -- made so the commercial software vendors for distribution system modeling and then also bring in folks from some of the open source software platforms and understand how PVs and distributed generation is being represented in some of the models.

And briefly, I just want to touch on the CPUC project. We are working with all the different California utilities and also the National Labs, we received about $2 million from the CPUC for approval for a project, we're obviously still trying to sign contracts and get everything underway, but what we're trying to do is look at screening distribution feeders and understanding, you know, based on the work that we've done already, how can we take all that research and then develop and validate a screening process with the goal of reducing the study time for interconnection and also the cost to stakeholders in the long run. So we're excited to start up that project.

That is, you know, originally in the agenda it talked about San Diego and their role in all of this, San Diego has partnered with our engineering team to deploy 25 monitors within their service territory and, so again, the distribution system monitors that I was talking about earlier, and so they're going to be looking at the one-second data, in addition to all the great data collection that UCSD has done, and other folks have done in San Diego, but using those monitors to look at specific feeders in their territory and then, again, go through the process of doing the analysis and later helping us to develop some sort of screen methodology that will be applicable to folks on a much larger scale than just feeder specific applications.

And I don't want to take too much time here, but I think I pretty much covered everything. You know, I don't want to downplay the effects on circuits, I mean, we have seen issues with feeder regulators and load tap changers, and voltage swings. The meeting that Mike had mentioned in New Jersey with IEEE later this week is really looking at how trip limits for 1547 match up with FERC 661A activities for bulk system impacts because one of the big issues is, when you have bulk system or transmission models that are not accurately aligned, you know, in the past distributing planning and transmission planning, you've always really been separate in the country, and so if you have transmission models that are not accurately representing distribution system and vice versa, you're going to have impacts there where those systems come together, and so on the modeling side that's really an important piece that we need to work through, but then also on the Codes and Standards side, there's a lot of efforts going on right now related to those activities.

So I am going to take the liberty to cut myself off here and I guess if there's any questions, I would be happy to answer them or defer you to other folks at EPRI who can also address some of the questions. Thank you.

COMMISSIONER PETERMAN: Thank you, Kristen. And thank *you* for staying on the line so late; if you're on the East Coast, then we've gone way into your dinner hour and past.

MS. NICOLE: That's okay, as long as the folks who are vacuuming didn't come in during my presentation, I was happy.

COMMISSIONER PETERMAN: No, there is at least one person here, myself, no, I'm just kidding, there are plenty of actual people here in-person and on the line enjoying your presentation. It was also nice to hear you speak about the coordination and conversations you're obviously having with NREL and with Sascha and some others, and it's good to know that the research community is engaging with each other. And Jamie asked the question earlier about what other research is needed, and we always like to hear that. So I don't have any direct question, but I'll turn to Chair Weisenmiller.

CHAIRMAN WEISENMILLER: I also wanted to thank you for participating in today's workshop.

MS. NICOLE: Thank you.

COMMISSIONER PETERMAN: I did appreciate you noting the need for analysis, particularly of energy efficiency and electric vehicles, those are needs for analysis across the board for us, particularly in our demand forecasts, and I'm glad you acknowledged the impact they can have on the distribution grid, as well.

MS. NICOLE: Uh-huh, yeah. Thank you.

COMMISSIONER PETERMAN: So I'll now turn the panel back over to Rachel.

MS. MACDONALD: Thank you, Commissioner

Peterman. I -- did you want to do more public or see if there was any public comment?

COMMISSIONER PETERMAN: Yeah, I think what we'll do is check to see if there's anyone on the phone, and then after that offer an opportunity for the panelists to ask each other any quick questions, or as well as give some responsive comments based on what you've heard. And I'm prepared to stay here until at least 5:00, to have the discussion, but also if people want a break, that's fine as well.

MS. KOROSEC: All right, the phone lines are open if there's anyone on the line who would like to make a comment. Going once, going twice. All right, I think the phone lines are clear and we don't have anyone on WebEx either.

COMMISSIONER PETERMAN: Or, Rachel, if you have a burning question, as well.

MS. MACDONALD: Well, I just wanted to check in with everyone. I think some of the panelists spoke of the timeframes for their projects, since we are looking at using this to inform our current reports and activities here, so maybe to wrap up, if you had any questions and dialogue for each other, and then to touch again about your projects and what you are looking at for as far as a timeframe for any near term results, as well as, as the projects are developing, how the results from these may inform interconnection -- better interconnection processes since that's what this workshop is for.

MR. LEWIS: I have a quick question. I'm familiar with Peter's results that got published last year, I think it was last year, maybe it was longer ago, but that was outstanding and we kind of stumbled upon them. Is there a database where a lot of the other results that Alexandra and others are putting -- that you go to and just find this, because it's great information, and so we need to get better sharing, even among those of us who are doing this kind of work.

MR. DAVIS: The one comment is we should be published pretty soon, we have been doing work with NREL on Hawaii for the last two years, collecting one-second data for two years, and they also have sensor data out there for 17 or 20 sites that NREL has, and we've been using that to do a lot of our analysis to look at how cloud cover comes over and impacts the 17 sensors that we're collecting data from. So there will be a report coming out on the two years of work effort that we just completed with NREL, but that is part of the Hawaii projects, and we are continuing to expand Hawaii and doing more feeders and doing analysis and doing all five islands over in Hawaii, of modeling PV impacts on those. So that's an ongoing project and will be going on for another two years, and then actually doing a lot of reports and presentations on that.

MR. LEWIS: So is there a place to get kind of current status data?

MR. DAVIS: Well, you can get on the NREL site and download that data. As far as the Hawaii data, you'd have to talk to the Hawaii utilities about whether or not that's public. I believe some of it is public since it's on monitors out on the line, but some of the data we're collecting is from some of the clients and some of the customers that are three-phase customers. And also, one of the interesting ones is that the employees who have PV have been offering their sites up and we've been collecting one-second data on PV sites on residential homes, but that -- you'd have to check with Hawaii how public those are available on those. But we've been using that data for our analysis.

DR. VON MEIER: And I can say in response to your question for the distribution monitoring project, we're not yet at the point of thinking how to make the data public. We're working, really, still on the step of utilities sharing the data with each other and with the research community for this project. Because I think we all have to be cognizant that there are security issues and certainly customer privacy issues that are important for the utilities and for all of us to be respectful of and, frankly, I think we're learning about what are the appropriate processes and protocols so that we can ensure the security. But at the same time, I agree with you fully that, going forward, it's going to be really important strategically to have the most education and learning and transparency from this information, so that's something that hopefully we can address in the future.

In response to Rachel about our timeframes, we're hoping to start pulling some of the existing measurements within the calendar year and to start setting up the processes for extracting -- for concatenating the data, really, and studying it. And that will be a process that will take into the next year, at which point I think we'll begin to do the gap analysis of what additional sensors and monitoring devices would be a good idea to install, and then we can start planning for the Phase II.

I also --I will wait my turn again, but I also have a question for Craig.

MS. MACDONALD: Thank you. Peter?

MR. EVANS: I was going to answer a slightly different question, so Linda Kelly is back there and she knows that we started developing tools for really understanding the direct grid impacts of distributed generation in, I think, 2002 or 2003, with the generous support of the Energy Commission. And it occurred to me sitting here today that this is maybe one of the first times when we hear a lot of people talking about the need for these tools, so, yeah, we were ahead of the time back then, but I would encourage you as policy makers, these are great forums for people to share information and there's a lot of great projects going on, it almost feels like the perfect storm of, you know, commercial interests and tools and the utility interests, and so forth, but -- the "but" is that we all need to see these efforts turn into practices in action, and people who operate networks actually using new tools, and yielding better results., and better performing networks, and more transparency for more development of more renewables to accomplish the State's goals. And so I think that there's a sticking point where you get from pilot projects and research, and how the researchers help turn that into changes in practices, maybe things having to do with utility incentives, or maybe things having to do with managing -- what utilities I think rightly perceive as risk that they take on, and I think that's as legitimate as these technical challenges.

COMMISSIONER PETERMAN: Well, thank you, Peter, for that comment. And one of the things I've been thinking about as everyone is presenting is, okay, how do we move from these particular research projects to water deployment and I would be curious to hear particularly from the tools that you're already using, whether in terms of the opportunity to scale those tools, whether the challenge is cost, is it expertise, or is it just proof of concept which you're doing now? And also, in your written comments, if you have particular recommendations on how we make that transition, or even successful examples of the transition from tools to action, greatly appreciated.

MR. LEWIS: Was that a question?

COMMISSIONER PETERMAN: It was a question, yes.

MR. LEWIS: Yeah, okay.

COMMISSIONER PETERMAN: Yes. Would you like to answer it?

MR. LEWIS: I'd like to --

COMMISSIONER PETERMAN: Okay, go ahead.

MR. LEWIS: -- partially, I'll answer as I can. You know, I think that when you look at what's preventing these kind of tools to get adopted, it's really the activation energy, it's the upfront investment of populating the tools with the asset information, the customer data. It's putting in the SCADA, making sure that you're integrating the data flows from the SCAD systems and your GIS. And the reality is that, where the Clean Coalition sees the most proactive movement is from the municipal utilities out there; they're the ones that are really being progressive and moving to this Smart Energy future. The Investor-owned utilities, we're finding, are really being -- they're in a position where you're having to force them to do these things, for the most part. And I think that's true here in California. The Clean Coalition actually looked at what SMUD had done with their Feed-in Tariff program, they had provided mapping information. We essentially advocated at the CPUC and got the CPUC to force the Investor-Owned Utilities to provide that mapping information, that's why that mapping information is available now, and it's gotten better, and we keep fighting to make it better and better and more useful, but that was not proactive on the utilities to provide that information, and so there's activation energy, there is investment to populate these models, but it's something that has to be done for the betterment of the ratepayer.

MR. EVANS: I actually would answer that different. That's probably partially true, although the activation energy isn't anywhere near as high as you might think. But I do think that there's a real issue, especially for the Investor-Owned Utilities, and I wouldn't even say "perceived risk," it's "real risk." And so, if utilities have a greater level of distributed generation in their systems, and something goes wrong, I think we all know how that's going to turn out. And so I think that there are probably policies and also -- not necessarily financial rewards, but certainly mechanisms for financial cost recovery that recognize that there are costs, activation energy isn't cost-free, there are costs and the utilities should be compensated for incurring those costs. And also, there's risk. And in the end, we all win. But the utilities need to understand that, you know, we're working on this together and, as they help to implement a State policy, they're not going to get beaten up if there ends up being things that none of us foresaw to occur.

MS. MACDONALD: Thank you. Kristen.

MS. NICOLE: Yeah, sorry, still here. I just wanted to add that, for the CPUC project, assuming that as long as the paperwork gets signed, and hopefully it should -- we're looking at a timeframe of about two years -- so we're looking at a couple of deliverables within the rest of 2012, and then the project will be completed by the end of the year in 2013 for that timeline. I do just want to mention that, as far as reporting out results, we -- unfortunately, most of EPRI's deliverables kind of come out at the end of the year, however, we do have a lot of researchers working throughout the year at different timeframes on different types of projects, and a lot of that research, some is private for a little while, I think everything becomes public after a few years, and then some of those reports are public, as well. So I would encourage folks to visit the website and check in regularly. And not only at EPRI, but also at NREL and Sandia since we're all working so close together.

When we were -- so through the DOE program, after the RFI studies were completed in 2008 for FERC integration, for solar, we developed this website, it's the High Penetration Solar Portal, and I do just want to put in a plug for that because, you know, the idea of it is that everyone travels too much, there's so many different meetings, it's hard to keep up with all the different results, but really that was supposed to be a, you know, it's a DOE website sanctioned by folks up there, so we're able to get access to information related to grid integration, and if we can just keep that technically accurate and, folks who are in the research community or who are in the commercial community, if you're actively on that site trying to provide input to the folks who are managing it, I think that would be a really helpful way for folks -- you know, it's a great resource for students, but it's also really good for folks in the industry.

My last -- I'll get off my soapbox -- but just talking about how to move tools from where we are now into deployment, I do want to repeat that the gentleman said, I'm sorry, I forgot who it was, but regarding reliability, we're looking at -- you know, the big issue with a lot of the modeling activities that are going on is that, if you do have errors in those models, it will translate into reliability concerns. And I think for us, you know, you have this great research tool like GridLAB-d or OpenDSS, but there is a learning curve to these tools. They're all open source, but any time you change different operator models, or you know, different simulation tools, there is a time lag there where there are folks at utilities in the field who are working with equipment and have practices that also need to be adjusted, and so I would just like to put in a plug for those folks that, you know, it does take time sometimes to implement these.

COMMISSIONER PETERMAN: Thank you. I was just going to say let's do final comment, and so if you wanted to start, Ron.

MR. DAVIS: Yeah, just the one comment I was going to say was, as far as Hawaii and Sacramento goes, we're using public available tools that are already out in the market that the utilities are using, and they already have their database updated and they're actually using it and implementing it, and we've helped them develop the interface to take the GIS data, feed it right into the models, do their simulations to use for operations, and for distribution planning. So it's ongoing active studies that are going on in actually using the models.

MS. MACDONALD: Peter.

MR. EVANS: I don’t have anything to add, just thanks for your support on these topics.

DR. VON MEIER: Let me clarify one earlier remark I made about publishing the results, certainly, the conclusions and findings from the data analysis will be a publicly accessible report, it's the raw data that we're talking about, having to understand how it needs to be anonymized or treated before it can be put online for everyone to see, we're not there yet.

And, you know, in closing, I think just reflecting on these last several hours, I think we've heard a very powerful argument for the necessity of a Smart Grid to enable decarbonized electricity. And I think it is incumbent on all of us working in this field to help education the public about this being really an important reason for this investment in Smart Technology, which frankly will cost some money and to have the public support behind it because I do believe that the public supports the policy.

MS. MACDONALD: Thank you. Jamie.

MR. PATTERSON: You know, I really don't have anything to add except that I do hope that -- this has been very informative for me to listen in today and hear about the concerns, it gives me topics for future research, and I look forward to working with all the researchers that have testified here today at this workshop.

MR. LEWIS: I wish Jamie had told me, to get CEC funding, you had to sit on that side of the table. The one thing I'll add here is that the Governor has put out a goal for 12 gigawatts of distributed generation that represents 60 percent of the remainder of the 33 percent RPS goal, it's more than half of the RPS goal, is supposed to come from distributed generation. And for that to happen, policy makers, utilities, all of us, we need to get off of the paradigm of everything being central generation and planning around that, and start planning for high distributed generation case because that's what the Governor's goal is. And so the tools that we talked about on this panel are really a first step to making all of that a reality.

COMMISSIONER PETERMAN: Kristen?

MS. NICOLE: Yeah, I was just -- I don't think I mentioned this before, but I would just like to put in a plug for the folks who are involved with the WECC Renewable Energy Modeling Task Force. We have a man on our team, Pouyan Pourbeik and Abe Ellis at Sandia, who has been working on a lot of these issues for a long time, and what they've done over the past few years, on the transmission side, looked at how to develop generic models for wind plants, and now they're starting to try to figure out what those generic models might look like for PV, and it's just important work and sometimes I think those day-to-day efforts, like Codes and Standard, and task forces and working groups get lost in the big picture, and so I just wanted to put in a plug for that. And thank you for allowing me to speak.

COMMISSIONER PETERMAN: And thank you for that plug. I represent the Commission on some WECC Boards, if you will, and I was just at a meeting the other week in Portland where we were talking about DG and some of the modeling that's happening WECC-wide, and how we can learn from each other's experiences. So thank you very much. Oh, we may have -- we have someone who said they were going to give public comments, we'll give them one more opportunity.

MS. KOROSEC: We're trying to send the phone number information right now and get the right number of the person because they apparently are off-site and don't have the notice.

COMMISSIONER PETERMA: Well, as you're doing that, let me use this opportunity to say thank you very much to our panelists. It is not easy to pull in the last panel of the day, but I've appreciated and learned a lot, and thank you for participating and the work that you're doing. Thanks to all the panelists, speakers, and I also want to give particular shout out and thank you for our moderators, we've got Rachel on this panel, and previously we had Linda and Mark, they are all experts in their own right in this field, and I encourage you to put them on panels going forward, and I'm sorry we didn't have more time to hear their perspective, but they were instrumental in focusing the agenda for this panel, as well as getting all the panelists together and keeping them to a reasonable presentation period. So thank you so much.

MR. WHITE: Madam Chair, this is John White.

COMMISSIONER PETERMAN: Yes, John. We were waiting for your public comment. Please, go ahead.

MR. WHITE: I apologize for not being there in person and for coming in late, but I’m in the process of moving and we've had some delays. I wanted to return a little bit to a subject that, I understand, was discussed this morning regarding the generation scenarios and the Long Term Procurement Planning that ISO was doing and that CEC and the PUC are collaborating on. As we've come to realize, the transmission planning and the planning for resources and ultimately procurement all are going to need in the future to be linked together. And the DRECP and the Solar PEIS for the Bureau of Land Management are focusing on the areas that they want to see renewable development occur. Those two areas that are highlighted and are important to integrate the transmission with the procurement and the environmental protection, are Imperial and East Riverside, and in the West Mojave. We are especially concerned with the Cost Contained Scenario because we think this doesn't reflect what we think is likely to be the future commercial and environmental preference that will be in these areas, and particular to West Mojave. So this is -- one of the things we're struggling with, and the Commission has done a really good job of helping try to sync up the various procurement and planning exercises of the ISO, the PUC, and the CEC, and we're getting closer, but we're still not quite all there and I think, in fairness, the PUC staff hasn't had as much familiarity with some of the land use planning and resource identification work that has been going on. And so I just wanted to reinforce the importance of using the commercial case that we think reflects both the likelihood of development, as well as the environmental preference that's emerging for less conflict in these areas than some of the other areas that have been developed. That would be my comment, and I apologize for not being there in person, and I appreciate you letting me have a moment to have these words.

COMMISSIONER PETERMAN: Thank you, John. And I think if you go back and look at the transcript from this morning where we talked to someone, similar comments were raised, and so we've noted them.

MR. WHITE: Great. Thank you.

CHAIRMAN WEISENMILLER: Suzanne, do you want to mention when the written comments are due and when the next couple workshops are?

MS. KOROSECS: Yeah, comments are due by COB of May 21st, that’s a week from today, and other workshops are coming up May 22nd, May 30th, June 6th, and June

11th.

COMMISSIONER PETERMAN: So Renewables Cost and Retail Rate Impacts, the 22nd, which I believe is next Tuesday, so join us, we're looking forward to it, and thank you all, particularly thanks to Suzanne Korosec and the IEPR team for another well orchestrated workshop. And with that, we are adjourned.

(Adjourned at 5:04 P.M.)