BEFORE THE
CALIFORNIA ENERGY COMMISSION (CEC)

In the matter of	)
	) Docket No. 13-IEP-1E
2013 Integrated Energy	)
Policy Report (2013 IEPR)	)

LEAD COMMISSIONER WORKSHOP ON
CALIFORNIA AND WESTERN STATES TRANSMISSION PLANNING
AND PERMITTING ISSUES

California Energy Commission
Hearing Room A
1516 9th Street
Sacramento, California

Tuesday, May 7, 2013
1:30 P.M.

Reported by:
Peter Petty

APPEARANCES

COMMISSIONERS

Robert B. Weisenmiller, Chair, CEC
Andrew McAllister, Lead Commissioner IEPR
Karen Douglas, Lead Commissioner Siting
Janea Scott, Commissioner
Kelly Foley, Advisor to Commissioner Hochschild

STAFF

Suzanne Korosec
Judy Grau
Grace Anderson
Bill Chamberlain, Retired Chief Counsel
Mark Hesters

Also Present (* via telephone/WebEx)

Presenters

Lorenzo Kristov, California Independent System Operator (CISO)
Neil Millar, CISO
Kevin Richardson, Southern California Edison

Panelists

Joe Desmond, BrightSource Energy
Peter Weiner, Paul Hasting, LLP for Abengoa Solar
*Bob Dowds, Mangano Homes Inc. for Westlands Solar Park
Renee L. Robin, SunPower Corp.
Manuel Alvarez, So Cal Edison
Diane Ross-Leech, PG&E
Tony Braun: California Municipal Utilities Association
Robert Strauss, CPUC
Ali Amirali, Startrans IO, LLC
Carl Zichella, Rep of WECC's Environmental Data Task Force

Public Comment

Jeff Gates, Duke American Transmission Co.
Jesus Arredondo, Wyoming Infrastructure Authority
David Smith, Transwest Express

INDEX

INDEX (Contin.)

P R O C E E D I N G S

MAY 7, 2013 1:36 P.M.

MS. KOROSEC: Good afternoon, everyone. I'm Suzanne Korosec. I manage the Energy Commission's Integrated Energy Policy Report Unit. Welcome to this afternoon's workshop on Transmission Planning and Permitting Issues in California and Western States.

Apologies to those of you who were at this morning's workshop and who already heard my spiel, but I need to cover a few quick housekeeping items before we get started.

Restrooms are in the atrium out the double doors and to your left. There are glass exit doors there that you should not use because they're for staff only and it will set off an alarm. We have a snack room on the second floor at the top of the atrium stairs under the white awning. If there's an emergency and we need to evacuate the building, please follow staff out of the building to park that's kitty corner to the building, Roosevelt Park, and wait there until we get the all clear signal.

This afternoon's workshop is being broadcast through our WebEx Conferencing System and you do need to be aware that you are being recorded. We'll make the audio recording available on our website in a few days and a written transcript will be posted in about two weeks.

Judy is going to give an overview of the agenda in a few moments, but I do want to let everyone know that, in addition to opportunities for questions during the afternoon, we've also set aside time at the end of the workshop for more general public comments. At that point, we'll take comments first from those of you here in the room, followed by people on WebEx, and then those participating by phone only. At any point during the afternoon if you're making comments or asking questions, please come up to a microphone so that the people on WebEx can hear you and so that we make sure we get you on the record. We also ask that you give our Court Reporter a business card so we get your name and your affiliation correct.

For WebEx participants, you can use the chat function to let our WebEx coordinator know that you have a question or comment. We'll either relay your question or open your line at the appropriate time. And for phone-in only participants, we'll open the phone lines after we've taken comments from the folks in the room and the WebEx participants. And it's helpful if you can keep your phone on mute unless you want to speak so that we minimize the feedback that we get when we open the lines.

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

In terms of context for today's workshop, the Energy Commission is required under statute to adopt a Strategic Transmission Investment Plan as a part of each Biennial IEPR. In addition to that requirement, the 2012 IEPR Update's Renewable Action Plan pointed out that transmission interconnections costs and requirements remain a major challenge to renewable development in California.

And the plan emphasized the need for progress on environmental analysis and licensing of transmission projects that are needed to deliver remote renewable generation to load centers, along with the need to streamline transmission permitting to reduce the lag time between transmission and generation permitting.

The Renewable Action Plan recommended developing milestones for each critical transmission project and monitoring progress towards meeting those milestones, and also recommended that the Energy Commission hold a workshop in 2013 to vet options to promote timely approval of in-state transmission projects needed to support renewable development.

The plan also recommended that the CEC hold an annual workshop under the direction of the Lead Commissioner for renewables to highlight progress on implementing the recommendations contained in the Renewable Action Plan, including the recommendation that is the subject of today's workshop. And we expect the first of those annual workshops to take place in early 2014.

So without further ado, I'll turn it over to Commissioner McAllister for opening remarks.

COMMISSIONER MCALLISTER: Great. Thank you, Suzanne. So thank you all for coming. Again, many of you were here this morning, so I appreciate your sticking it out.

And we had a really nice session this morning, I think it was very informative, and I certainly appreciated the level and the civility of the interaction, I thought it was just really excellent, and looking forward to more of the same certainly on the topical areas.

I want to let our panelists speak and, on that note, I would just express my appreciation not only to you for coming, but also to staff for lining up such great workshops and getting the right people on the panels and setting things up in a way that allows us to have this conversation, so I think that's very helpful.

In the morning, we talked about projects, and now we're going to talk about transmission, obviously two sides of the same coin, and it's really all about getting responsible, well vetted projects done and delivering energy to meet our long term goals in a responsible stakeholder process, in a relatively streamlined and hopefully not overly onerous, but certainly responsible process. And there are a lot of voices validly -- that are legitimately and I think essentially at the table, and we're trying to facilitate that process.

And under Commissioner Douglas' leadership on the DRECP, and really across the board in our various areas across the Commission, this morning we heard Commissioner Scott, who has joined me, thank you again for coming, the appreciation for her role with the Federal Government previously, you know, the Commission is really taking the Governor -- starting with the Governor and the Commission -- is really taking this very seriously because it really is a fundamental process to meeting our long term State goals and it's not going to happen unless we're successful here in this forum today.

So I am excited to preside over this as far as within the IEPR process, but it is actually broad and requires continual engagement; it doesn't end with the IEPR report, it is an ongoing living breathing thing.

So I really appreciate your active and continued engagement here, and would offer the dais to Commissioner Scott to see if she has anything she would like to add. No. Okay, great, I said it all. Chair Weisenmiller hopefully will join us here presently, but absent that, I will pass it back to staff. Thank you.

MS. GRAU: All right, thank you very much. My name is Judy Grau. I'm with the Commission's Strategic Transmission Planning Office. And I just want to go over a few items quickly on the agenda.

We do have four presentations, with each of those about 15 minutes, and we'll allow five minutes of Q&A after each of those presentations. In the first two presentations we want to highlight two emerging trends in the Western Interconnection, and so the first of these, Grace Anderson of the Energy Commission staff will be talking about the Western Electricity Coordinating Council Restructuring effort. And just as a note, staff is not an advocate for restructuring, per se, so the purpose of Grace's presentation here is to just give a lay of the land.

And then we have Lorenzo Kristov from the California Independent System Operator, and he will be giving a presentation on the California ISO's Energy Imbalance Market Design Straw Proposal.

And then we have Neil Millar, also from the California ISO, and he'll be talking about three main areas in his presentation, the transmission underway to meet the 33% Renewables Portfolio Standard, the status of the projects in the ISO's interconnection queue, and the ISO's transmission planning process's competitive solicitation process.

And then as a follow-on to that, we have Kevin Richardson from Southern California Edison, and he will be giving a presentation on development focus area suitability and transmission planning.

And for those of you who were here this morning, that DFA acronym was discussed quite a bit, those are the Development Focus Areas that are being addressed in the Desert Renewable Energy Conservation Plan effort, and so if you were here this morning, you heard Roger Johnson's description of that and the follow-on from that.

Then we will go into our panel discussion. We're hoping to begin that by 3:00 and end it no later than 4:30. Mark Hesters is already seated here, will be the Moderator, and he will have more instructions when we get to that point. We will allow about an hour and a half, and, so, for the panelists that means five minutes of prepared remarks; again, we'll go around the table as they did this morning, and then hopefully we'll have time for more in-depth discussion, not just the go-around the table.

We will try to get to public comments by 4:30. We know from this morning that I believe we already know we want to hear from Bob Smith of the Power Company of Wyoming and Chris Ellison of Pathfinder Zephyr; I'm sure there are more among you, but those are the two we heard want to speak this afternoon.

So as Suzanne mentioned this afternoon, this workshop continues the implementation for the 2012 IEPR Update's Renewable Action Plan, as well as adding to the record for the 2013 Strategic Transmission Investment Plan, which has been done biennially since 2005. And as noted in the 2013 IEPR Scoping Order, the Strategic Transmission Plan is not going to be a separate document as it has been in some prior cycles, but will be included in the overall policy report.

So with that, I'd like to introduce Grace Anderson, who will be giving the presentation on the restructuring at the WECC, and she has also Bill Chamberlain here to answer any questions from the dais or other folks, so we look forward to that. And you're ready to go, Grace.

MS. ANDERSON: So thank you, Commissioners, for putting this sort of 20,000-foot subject on your agenda, we're definitely not going to talk about specific transmission lines here right now, we're going to talk about the broader questions about how reliability is regulated in the Western Interconnection.

So in order to talk about proposed change, we have to first have the slide that talks about what the existing WECC structure is, what kind of a proposed structure and governance and functions and funding of this new approach might be, and then brainstorm just briefly on what implications that might have for California and the West, and just highlight a few milestones that are coming up in the near term.

So right now, WECC is a stakeholder driven body, it has seven stakeholder member classes. These are the large transmission owners, small transmission owners, other lines of electric business, which is primarily generators and marketers, states and provinces, end-users, Canadians, and other. And this is important because these classes elect the directors of a stakeholder board. This is a large hybrid board which consists of 26 stakeholder directors, and then seven non-affiliated directors, also the CEO votes, so that makes 34 -- in case you're doing the math. It's very large. It's called a hybrid board because it's a combination of stakeholders, directors, and non-affiliated directors. It' incorporated under a

501(C)(6), which is a not for profit trade association.

So why might we propose to restructure WECC? And as Judy said, I'm not here as an advocate, and I'm not actually even directly involved in this, I'm the messenger today of sort of the lay of the land as it currently stands. And the decision to restructure is not final at WECC. The most important reason is to improve reliability in the Western Interconnection, and pretty much avoid another September 2011 outage. This current initiative to restructure really grew out of that outage, it responds to significant pressure from NERC and FERC on the WECC Board to change its governance and also its structure.

The goals for restructuring could allow increasing independence of the Board improving oversight and being able to participate in all forms of analysis, in particular event analyses of outages. And this sounds esoteric, but what happened after September 2011 is that WECC, the Western Interconnection, was excluded from participating in the review of the causes of the outage because they were viewed as both operating the system and also developing the standards and compliance function, so it was sort of felt that, you know, they couldn't actively perform both roles, so that reduced the quality, at least the West thought, of the analyses. Also, this is an opportunity to confirm the funding mechanism for reliability, so we're going to talk a little bit more about those things.

This slide indicates that there are a lot of controversial issues, there's hundreds of thousands of hours that have been spent on this since spring of 2012. I've indicated these are largely resolved, and I indicate that because of the votes of the WECC Board of Directors, and also the views of the state and provincial entity that is closely participating in this. Now, that does not mean that all the members of WECC concur that these issues are resolved, there isn't consensus on everything at this time, and I'll talk more about that later. But what has been resolved is that they're going to bifurcate, or they have proposed to bifurcate, into two entities, a new entity and then the continuing WECC regional entity. We'll talk more about those functions in a moment. They've decided that the Boards of Directors will be independent, they've decided on the number of member classes, the advisory committees, the proposed funding mechanism, and the legal incorporation status.

This slide, we're on page 6, shows this bifurcated structure in a very simple way. You see there are two boxes, a green one and a brown one, and they're separate. They each have their own member advisory committee and this creature called WIRAB, the Western

Interconnection Reliability Advisory Body, which is the Western States, will advise both of those boxes. So what will the governance of the entities be? They will each have independent Boards of Directors, they'll be independent from one another and they'll be independent from any member of WECC. So this will no longer be a stakeholder board, it will not even be a hybrid board. There's going to be five member classes, they're listed on this slide, and it's important to see that states are still a class, and that was one of the many fights to keep the states actually a part -- an immediate class of WECC. This is important because the five-member classes will each nominate and elect three representatives to what's called Strong Member Advisory Committees that are responsible for providing the member class perspective to the Board. So that will be a 15-person advisory group, and there will be one for each entity. And a final change is that these entities will be incorporated as 501(C)(4) entities, which is the "best interest of public welfare," no longer a trade association.

So what are the functions of these two regional entities? First, the new one, the Reliability Coordination Company (RCCo), will conduct reliability coordination, it's the real time operating reliability with the wide area of view, which authorizes implementation of balanced schedules between Balancing Authority areas, and ensures communication. These two function together, the RC function and the IA, Interchange Authority function, are being moved out of WECC and into an independent entity. It will also have the authority to direct other functional entities under the NERC functional model of reliability participation to take actions to ensure that that entity's area operates reliably. RC will do next day and seasonal planning.

Slide 9 summarizes the functions of the regional entity, which is WECC as we know it, but minus those two important functions that have been spun off to the independent new corporation. So very important, standards development, standards compliance monitoring and enforcement under the delegation agreement from NERC. WECC will do the event analyses that it was precluded from doing because it was also the RC and still is as we speak today, the RC, the Reliability System real time coordinator.

WECC will continue to do some reliability analysis and resource adequacy assessment. It will perform its long time very important transmission line path rating where upgraded existing lines, or new lines, are granted the rating at which they may operate in the Interconnection. And it's also proposed that WECC would continue to host WREGIS, the Renewable Energy Generation Information System and also Interconnection-wide transmission planning.

So one short slide here on funding. WECC has filed with FERC a petition for a Declaratory Order regarding Section 215 of the Federal Power Act, funding for both entities, and that is how this function has been performed in the past. The states have filed in support and a decision is possible later this month or June, and of course they will continue their negotiated agreements for funding with Canada and Mexico, which has been successful in the past.

So with that very high level summary, I tried to brainstorm what might be possible implications for California and the West. And the first one is clear: if restructuring goes forward with the governance that is proposed, WECC member classes will lose their direct representation under an independent board, there will no longer be directors that represent, you know, Class 5 state and provincial entities, or Class 1 large transmission owners. The second point is that, since it's an independent and non-affiliated board for both entities, it's possible that Directors from the eastern Interconnection may be more predominant on the Board because they're more likely to not have economic or other ties to WECC members. An independent board could be more inclined to RTO-like functions that we do not have in the West, and you might think that's a good implication, or you might think it's a bad implication. Contingency reserves or other requirements for the operation of the existing transmission system could change. And then finally, the role and the technical strength of traditional WECC standing committees, which have been very important in the operation of WECC and the Interconnection, they could diminish depending on how their role is defined going forward, and that's the repository of the technical expertise, really, of the Balancing Area's utilities and others in the West. And I mentioned before that WREGIS and Interconnection-wide transmission planning is proposed to remain with the Regional entity, WECC, but there's dispute over that. That would be important to California because we rely on WREGIS and we have put a high priority on transmission planning.

So I just mention that this is not a done deal. There are controversial issues, some of those are still pending, and I will just say that there is a Class 1 and 2 transmission owner coalition and they're not fully comfortable with what's being proposed, they are particularly uncomfortable with the governance of the new entity, the RCCo, and they've submitted an open letter to the Interconnection, to WECC, dated April 11th and, you know, if you're interested in understanding this better, I really encourage you to look at that, and we could add it to the docket if we wished, but they really feel that an independent Board puts too much distance between those who are making the budget decisions and the standard decisions from those Balancing Areas that actually have to operate the system and pay the fines if they are unable to comply. So they have their own set of Bylaw changes, which has been put forward.

Also very important is the clarifying of the relationships between the two entities, particularly with respect to data sharing, and then also sort of sorting out the details on the reliability assessment functions. And there is still some dispute about whether either entity should continue to host WREGIS.

So where is it going from here? Well, the opportunities are right in front of us, there's four regional meetings in May, one of those on the 13th at the ISO in Folsom, all WECC members will have an opportunity to vote on the Bylaw changes and new Bylaws in June in San Diego, and the Board itself will consider approval of bifurcation and bylaws, depending on what the membership vote is, also in June. And if there's a decision to move forward, then there could be election of those fairly important 15-person member stakeholder member advisory committees also at that meeting. Later, then, if this moves forward, there will be the nomination of the independent directors, the membership vote on those directors, and of course, since all of this authority is delegated through agreements under the Federal Government structure, there will be orders and decisions by NERC and FERC on the delegation agreements and the Bylaws, and it's possible that this new entity, the RCCo, could go live in January of 2014.

And with that, just one more slide, but it's really just to suggest that, whatever you feel about this, your WECC member has an opportunity to vote, you can participate in selecting member advisory committees, you could choose to identify strong Western candidates for independent directors and, when the time is right, support funding through Section 215 at FERC.

And Bill Chamberlain is here, he's our former Chief Counsel, and he's a charter member of the WECC Board of Directors and we're fortunate that he was able to be with us today to help explore any questions. Thank you.

COMMISSIONER MCALLISTER: Okay, thank you very much. I do have one question, actually. So where -- you know, it seems like a decision from FERC, I guess is imminent on this? I guess my question is, what is the process there? Has there been a comment period? And kind of has FERC, you know, taken -- what process have they followed to kind of get to the proposed decision path?

MS. ANDERSON: Well, the only decision, that we hope is imminent, is with respect to the Declaratory Order on the eligibility of these functions to be funded under Section 215 of the Federal Power Act. The actual Bylaws and delegation agreements would emerge later this year, but they have their normal intervention process, and members of the WECC have intervened in that Declaratory Order process, including the ISO has intervened at FERC with respect to the timing of the Declaratory Order decision.

Well, we have a couple minutes, maybe we'll just let Bill make a few observations as he's the Chair of the Governance and Nominating Committee of the WECC, the current WECC Board of Directors. And I know he's probably the main author of these Bylaws.

MR. CHAMBERLAIN: Former Chair. Jim Shettler of SMUD is now the Chair of the Governance Nominating Committee.

I guess the main thing that I wanted to say was that the driving force here was the fact that, you know, WECC originally was set up to be the regional entity and to handle standards, the compliance and the enforcement of the standards. Back in 1996, there were some outages that caused the Interconnection to -- caused the large entities in the Interconnection to realize that they needed to set up these reliability coordinators. And they were originally set up in host facilities, Bonneville Power Administration had one, CAISO had one, and there was one at the Western Power Administration -- Western Area Power Administration offices in Colorado. But unfortunately, those three reliability coordinators were all using the software of their host facilities, and they weren't looking at the same screens, they had to call each other if there was a problem and try and figure out what was going on. And about three or four years into the creation of WECC, the WECC Board decided to fund and develop an Interconnection-wide Western system model. And the West Wide System Model became the platform for the new reliability coordinators that went live in 2009, and those were taken over by WECC. And it was because the standards provide for the reliability coordinators to be subject to certain requirements in the standards, and if they fail in their responsibilities under those standards, they can be fined. And so you had a potential conflict here between -- or at least an appearance of conflict if FERC and NERC were to do the event analysis with WECC in the room because WECC would both be providing information, but also potentially protecting its reliability coordinators. So that's the driving reason for this bifurcation.

The only other thing that I would add is I think the meeting on the 13th is at SMUD, rather than at the CAISO, but I could be wrong about that -- that might have been changed, but I would just suggest if anybody is planning to go to that, check out the location. Any other questions? Thanks.

MS. KOROSEC: All right, next we have Lorenzo Kristov.

MR. KRISTOV: Good afternoon, Commissioners and everyone. I want to give a little presentation about the ISO's Energy Imbalance Market, which is very much a work in progress at this point. And so I'll just start off with a little bit about the process. We really currently have two activities going in parallel. As you probably know, we signed a Memorandum of Understanding with PacifiCorp to implement an Energy Imbalance Market with them that would start up at the end of 2014. But in parallel to that, we are also conducting a more conventional ISO stakeholder process where we do the design work and the design effort to figure out the details and the rules and what goes into our tariff, and all of that, the idea being that we didn't want to just create something that fits an ISO PacifiCorp Energy Imbalance Market, but we wanted to do something that would enable other Balancing Areas, if they want to in the future, to join that Imbalance Market, and so we wanted to design with that more generic and flexible capability in mind. So these things go in parallel.

On the PacifiCorp agreement, we filed an implementation agreement at FERC just I believe in the last couple of weeks, and we started a stakeholder process at the ISO, also a few weeks ago, where we put out what we call a Design Straw Proposal, and that's pretty typical ISO jargon for our stakeholder initiatives. We start with something that we call a Straw Proposal with the idea that there's lots of details that remain to be worked out, and we're looking for stakeholder interaction to develop the rest of the details.

These two pieces will come together in 2014 so that they are consistent, and then ultimately we go through the whole process for leading up to implementation that involves testing and market simulation and so on. So that's the process that's unfolding.

As many of you know who follow activities in the West, the idea of an Energy Imbalance Market or Real Time Imbalance Market has been floated for years, parties have talked about it, they've argued about the benefits and whether the costs are worth the benefits, and so on. It's been under discussion, some proponents, some opponents, but there's been a sense that, at least on the part of some parties, that it would be desirable to have some facility to trade energy imbalances in real time when one area had surplus and another area had a deficiency, or when there was congestion relief, to manage loop flow, and so on, rather than each Balancing Area having to do it completely on its own, that there would be efficiency gains. Even before those were measured, they were at least intuited that they would be there.

What's been at least some of the technical impediments is that, as parties thought about implementing such a thing, there would have to be a huge investment upfront in creating the software and systems, and the capability, and metering, and all that stuff that goes with it in order to implement something, and because it would be a high kind of capital intensive sum cost, then you'd need a critical mass of participating balancing areas in order to make it worthwhile and get it off the ground and trying to get that critical mass together to agree on the timing and the nature and all of that just didn't allow it to really move anywhere.

So the ISO came in to the discussions in 2011 largely at the request of some of the Western

Commissioners that had an EIM evaluation activity going on and, as we looked at the problem and we looked at the market design that we had developed over the last many years, we put a new market system into place in April of 2009, and we realized that what we could do is take our existing platform and essentially expand some of the capabilities of it to any Balancing Area that wanted to participate with us. We did not need a critical mass. One entity that wanted to join, we could actually create something by simply extending our network model, and utilizing our existing software with some relatively minor changes to enable the Real Time exchange of imbalances to take place, so that offered a huge simplification because it eliminated the problem of having to have a critical mass, it eliminated the problem of a huge capital investment upfront.

And so, starting with PacifiCorp, there's now been a willingness to move forward on it, and so that's where we're starting. Also, as different Balancing Authorities want to join, there's a lot of flexibility for them preserving the autonomy of how they want to schedule their resources to meet their demand, and so on. They don't have to completely buy into the ISO market structure and the way we do things, there's really an ability to have a limited engagement through a narrowly defined Real

Time Imbalance structure, so some of the essentials that have to take place between the ISO and the Balancing Areas. And what I'm going to do in the next few slides is give you a very high level overview conceptually of how this thing will work, without getting into details, and there's references on the ISO website if you want more, and certainly you're invited to get engaged in the ISO stakeholder process if you really want to get into the details.

But certainly Network Modeling has to be the basis of it. We have to be able to monitor where there's going to be congestion within the other areas so that, when as we're issuing dispatch instructions, we know that they're feasible, so transmission monitoring. Then each of the Balancing Authorities will give us bids -- economic bids for their offers to increase or decrease generation, as well as self schedules, resources that they want to run at a specific level, they would give us that information, then we would, within the operating hour, send back dispatch instructions to them based off of what they've given us. This is the overview and the next few slides will give you a little more detail. And then there's a settlement process whereby we issue settlement statements that are associated with the imbalances, and they respond by sending money.

A couple bits of jargon -- EIM entity, that phrase is used throughout to mean Balancing Area that joins the EIM structure. EIM participant is the individual generating company, it could be an independent generator, or it could be a vertically integrated utility that has generating resources, but it's those participants that are actually scheduling energy or offering energy with economic bids into the market, so those are the participants.

So it starts out with building what we call the full network model, that's something we've had in the new ISO market structure which essentially models it to the greatest extent possible, a precise version of what the electrical network looks like, so that we're always trying to maintain that alignment between the market, the economics, and the physics of the system, what's decided, what's cleared through the market, it's feasible on the electrical system. So we have to do the modeling exercise, and then we have a feature called the Master File, which is information on every one of the resources that's participating, how fast it can ramp and things like that, resource IDs, location, the type of resource. So that's the basic information.

On top of that, then, the EIM entity, that's the Balancing Area that's participating, creates a base schedule with us, and that can happen any time from day ahead timeframe up to about an hour or so before the operating hour. That base schedule they simply establish and we do very little to it, and I'll get to that in a moment. But that's the basis off of which any intra-hour variations or deviations are measured and settled.

So read this from the bottom up, starting with that base schedule that's submitted to us by the Balancing Area. We then monitor those bunch of things that are listed up above it, in other words, what kind of interchange is part of their schedule, updated information about contingencies, generation, or transmission outages, the most up to date forecasts of variable resources like wind and solar, the most up to date load forecasts. And what we do is we perform just what we call a minimum shift optimization to the base schedule to make sure that it's feasible, given all this new information, so it's really trying to make only minor adjustments, so that when we establish that base schedule, which will be the basis against which deviations are measured, then we have something that is feasible. Okay, so that results, then, in an adjusted base schedule and that becomes the basis, then, for the further actions.

Now, the next thing you're going to start reading from the bottom up, the Adjusted Base Schedule, is the baseline, now we still have some of those same types of information that are being incorporated, but now we're looking at every 15 minutes interval, and this is running about 30 minutes before the start of the 15-minute interval, and it's looking for needed adjustments that have 15-minute interval schedule based on dynamic contingencies, generation, or transmission outages, again, updates of the variable resource forecasts, updates of the load forecasts, and economic bids that are provided to us by the participants, that is, the entities that have generating facilities that want to participate in that market. And they would give us bids to buy and sell electricity in real time that would be applicable either to the 15-minute interval, or subsequently to the five minutes. So we put all of those things into our optimization and then what we come out with is 15-minute schedules, and that says for each of the entities that are participating, here's what we want you to do in this upcoming 15-minute interval, that is, maintain this operating level, produce this number of megawatts, megawatt hours over that interval, and then there would be some ramping conventions around that.

So after those 15-minute schedules are established, now we get into the five-minute interval balancing, which is where a lot of the more dynamic action happens. So again, reading from the bottom up, we have the awarded 15-minute schedule, which is a basis for five-minute deviations. We look at that whole list of ingredients above there and we incorporate into the model any applicable changes, we use the same set of economic bids that they gave us that were used for the 15; there's only one bid submission for each operating hour, so it's the same bids, and we now perform a five-minute optimization and this is happening somewhere around 10 to 15 -- I think it actually ends up about 7.5 minutes prior to the five-minute operating interval. So that, then, comes out with five-minute dispatch instructions that we're sending back to all of the generating resources, telling them where we want them to operate for that five-minute interval, how many megawatt hours to produce in a five-minute interval, and again ramping conventions about how they're supposed to move.

So after this is all done, we're collecting all the information about what they actually did. So we're doing now a settlement based on deviations. Starting now on the left side, start at the top this time, the adjusted base schedule is the thing that we created in the first step of this process, and we look at deviations between that and the 15-minute schedules. Each of those 15-minute schedules may have some difference to what was the adjusted base schedule, and there's a 15-minute energy price which is used to settle those deviations. Then you go to the five-minute dispatch and you're liable to see deviations between the five-minute dispatch and the 15-minute schedule. Similarly, when you get their meter data, the actual meter that tells us how much energy the resource put out in that five-minute interval could be different from the dispatch instruction itself. But both the five-minute dispatch and the actual meter data, those are going to be settled at the five-minute energy price, that's the deviation between what actually happened in real time and the 15-minute schedule. So then each of the scheduling coordinators, which are the entities representing the resources that are participating, they get a settlement statement and then, based on that settlement statement, they would essentially pay money that would be transacted through the ISO settlement, so parties that need to get paid for energy get paid, parties that need to pay for energy get paid.

Now the cost of participating, independent of the energy settlement itself, obviously if you're selling energy you're going to get paid for it, if you're buying, you're going to pay at the five-minute or the 15-minute price, but then there is a partition patient fee that covers the overhead of the system. In the ISO system, we call it the Grid Management Charge, or GMC, and it's a structure that we use to recover our budget, and it was redesigned in 2011 for the 2012 year where we simplified and basically it's based on very cost causation type of principles. So to the extent you're using the various market services, you're paying for the use of those.

So the GMC that's effective for 2014 through the end of 2014 will apply, then we're going to do another study and potentially revise for 2015. So there's a start-up cost if you want to join, which is three cents times your total annual energy usage, so that's megawatt hours, three cents per megawatt hour of your total energy volume for the year for the Balancing Area. That's the start-up cost that you pay, you ante up to get into the system; after that, it's all based on usage and there's an administrative rate of 19 cents per megawatt hour volume, and that's calculated by either of these two equations. It's paid both by the generation side and the load side, as our GMC is, that when we allocate the cost we look at measured load megawatt hours, we look at measured energy supply megawatt hours, and both of them pay based on a megawatt hour volume.

On the generation side, it's the maximum of either five percent of gross generation, or the total amount of generation imbalance energy, and this is an hourly settlement, so you're looking at this every hour, we're calculating your gross generation for the hour, your generation imbalance energy, and charging you 19 cents per megawatt hour for that hour.

On the load side, it's very similar, a maximum of five percent of gross load, or a load imbalance energy again at the five-minute and the 15-minute, there would be imbalances in both of those interval changes.

New EIM entities looking down towards the future as new parties want to participate in this, what we're doing for 2014 startup will be just with PacifiCorp, but if parties want to express interest in joining in the future, then we're going to set up a process -- we haven't got all of this established yet, but essentially we will be creating a process whereby parties apply, there will probably be a 12 to 18 month lead time where we need to do all the requisite modeling of the network, creating the master file for all the resources, etc., and creating all of the agreements that need to be put in place, the contractual agreements and arrangements. And, again, new entrants would pay that same start-up fee, the total of three cents per megawatt hour of demand. And all of this gets set up through an implementation agreement for each party because, once they join, they're subject to the tariff; but prior to joining, all of this comes under an implementation agreement that would be filed and approved by FERC, similar to what we have now in front of FERC for PacifiCorp.

Here is a link to our website where you can find some more information about this. There is an EIM specific training under development, but if you look under the ISO website -- sorry I didn't put it on here -- there's a "Stay Involved" heading on the main page, and then under that is "Stakeholder Processes," so if you looked at "Stakeholder Processes," there's about 40 or 50 of them and you'll see Energy Imbalance Market listed in there, and you can see what's going on with the stakeholder process. And that's basically it. I'm happy to take any questions.

COMMISSIONER MCALLISTER: Any questions? I wanted to acknowledge the arrival of Commissioners Scott and Douglas, Chair Weisenmiller, and Kelly Foley from Commissioner Hochschild's office. So we're complete once again.

I guess I'm just wondering generally, do you have any other conversations going on with any other PacifiCorp-like entities?

MR. KRISTOV: Nothing's in the realm of seriousness yet, you know, I think there's informal inquiries, tell us more about this, and people come to this -- I think we have a slightly different cast of characters coming to the stakeholder process because now other parties who are interested in seeing how the ISO process works and the design process, we're having more parties come and participate than just the ones who normally pay attention to ISO design questions. But, you know, that I know of there's no ongoing negotiations yet with anybody.

COMMISSIONER MCALLISTER: Good, thanks. It's exciting.

MS. KOROSEC: Our next speaker is Neil Millar.

MR. MILLAR: Thank you and good afternoon. My presentation covers a fairly wide range of topics, so I'll touch on the key points on several of these slides, move through, and then see what questions arise.

First off, I've provided a table here showing the bulk of the transmission projects that are underway, targeting meeting 33% Renewable Portfolio Standards by 2020. I should mention that there are a couple of clarifications and updates. Line 11 and line 13 are both listed as ISO pending and those are actually both approved now. And one other question that came up in response to the presentation was that the Imperial Valley C Station Project listed on line 10 is also a range of projects from 2013 to 2015, or a timeline of 2013 to 2015; if we can get the project earlier than 2015, that would be great, but this project is one of the first going out for a competitive solicitation, so we also needed to be realistic about enabling competition for that project. Otherwise, the bulk of this list is material that I think most of the stakeholders have seen before.

Oh, I should have also mentioned that probably for the context of permitting issues, the projects that are experiencing some more recent conversation about permitting and timelines are certainly the West of Devers project, as well as the Tehachapi project, and on line 7, the Cool Water-Lugo Project, so those are generating a fair bit of stakeholder interest around the timing of those projects moving forward.

Now I'll switch to just updating where we're at with the ISO queue of renewable projects. This table and graphic picture represents the queue up to and including cluster 6. The cluster 6 window just closed recently and generated an additional 5,400 megawatts of conventional plant interconnection requests and 4,200 megawatts approximately of additional renewable generation. So the current numbers were leaving us at 34,000 megawatts of renewables plus approximately 15,000 megawatts of conventional, and these will be in addition to this table.

In terms of the activity on the queue itself, as we've moved forward getting closer to 2020, more plans and procurement plans are firming up, the actual volume of generation in the ISO Interconnection Queue is dropping and getting more in line as it gradually approaches the amount of new generation we actually see necessary to meet the 2020 objectives. We're currently sitting at approximately 3,500 megawatts in the queue and that's quite a drop from the original -- from the 70,000 megawatts in July of 2011. Obviously, competition is good and important. The flip side is that an overheated queue also generates considerable uncertainty about the transmission projects.

This graph just demonstrates the progression of renewable energy in the ISO in terms of what is actually connecting and also clarifying both what's projected through projects that are under active development now, as well as what's necessary in our calculation to meet the 33% RPS by 2020.

We have recently held at downsizing request window. The ISO process does require generation to apply for a specific amount of generation and has fairly tight tolerances about variations from that installed capacity. That's necessary to ensure that we don't build unnecessary transmission from more optimistic interconnection requests than ultimately proceed. We did run a onetime downsizing study request window that allowed us to examine all of the requests that we're seeking to downsize simultaneously. There was a great deal of stakeholder interest in developing this process. We did receive some level of downsizing request, but I don't think it was quite at the level that some of the stakeholders were anticipating.

In terms of the study process and where we're at on getting agreements in place, we have been making good progress with all cluster studies completed through Cluster 4, representing approximately 30,000 megawatts of generation. The Cluster 5 studies have recently completed the Phase I and we're gearing up for the Phase II analysis starting this summer. And that will be informed by the postings of who posts and moves forward in both Clusters 3 and 4, where the second postings are due, as well as the Cluster 5 initial postings.

This does leave a fairly impressive list of Generator Interconnection Agreements (GIA) left to be negotiated, approximately 19,000 megawatts are outstanding with a total of 153 contracts to put in place. So the good news is that the cluster process is working, the downside is that the cluster process is working.

The impacts of adding additional flexibility through downsizing, obviously the downsizing revisions will impact the negotiations. We also have to look at these outstanding generator Interconnection Agreements and make any necessary adjustments responding to the impacts of the downsizing requests.

I'm now going to jump over to talk a bit about the revisions that the ISO had recently made and were approved and implemented for Cluster 5 on the Generator Interconnection and Deliverability Allocation Procedures, this is the GIDAP acronym that's been floating around. This major shift in our interconnection process really focused on aligning and integrating the generator interconnection process with our annual transmission planning process. It was meant to address really the three major deficiencies that we saw with the current processes in addressing especially very large volumes of generator requests that were far beyond the practical levels that we're likely to proceed. First, was that this change allowed us to plan and approve major Ratepayer-funded upgrades through the single, through the holistic transmission planning process, rather than having major network upgrades that would ultimately be funded by Ratepayers proceeding on one track through the transmission planning process and other projects also being identified through the generator interconnection process.

Second was that the Ratepayers would recover the delivery upgrade costs only for recovered delivery network upgrade costs, only for the projects that were aligned with the planning portfolios developed in concert with and through the efforts of the CPUC and the CEC and other stakeholders.

The third issue was a real need to ensure that the study results as we moved through the generator interconnection process produced realistic results even if the queue volumes were extremely high. And this latter concern is one that actually triggered the need for what was to become known as the Cluster 1 through 4 Technical Bulletin. In a cluster study approach, we study the entire amount of generation that applied to interconnect in a particular electrical area, one area at a time. If you double or triple or quadruple the amount of generation applying in that area, especially if it's at levels far beyond what we realistically expect to see, the costs may be going up more or less linearly on a dollar per megawatt basis, but the time that it would take to implement those much bigger projects that have to reach much further afield to deliver the generation to the load also increases considerably.

The negative consequence of all of this was that, in areas that were prime interest and overheated, timelines were being produced that actually were unacceptable and could have accidentally sterilized the whole area for development. So that was not acceptable, we needed to come up with alternatives that were more geared to a practical amount of generation that could realistically proceed in these areas.

As I mentioned, the interim solution that we landed on was the means of removing some of these high cost and also extremely long lead time projects through the use of a Technical Bulletin. I've captured the key points here, but the premise was the most important part of why we had to take this step.

Moving back to the GIDAP process itself, the key point was that, looking over the track record of the major projects moving forward, the most significant and costly interconnection upgrades are actually to ensure resource adequacy deliverability, so we really needed a way to focus on developing a transmission plan that met the needs of the generation portfolios, and to some extent making it easier for projects to move forward in good areas, while still enabling projects that were not in those favored areas to also move forward if they chose through the open access requirements.

Just moving through the basic steps of the process, the first Phase I study and looking at Cluster 5, assesses the deliverability for a reasonable amount of generation, then, based on those results, generation interconnection customers make a choice, are they willing to move forward on their own and pay their own way? Or is it necessary for them to take the benefit of the rate base deliverability capacity through the annual transmission planning process in order for them to move forward? With the results of that information, that allows us to then really fine tune the Phase II studies much more clearly looking at continuing on with the transmission plan deliverability, and then looking at the additional deliverability required for the projects that want to move forward on their own.

This is a fairly complicated slide laying out the different interwoven processes. One of the things I would emphasize is that this makes it even more important than usual that the ISO stay on schedule with the different transmission plans in the interconnection processes because these have been heavily intertwined and really count on the information from each process feeding into the next.

Now I'd like to touch a few minutes on the annual transmission planning exercise and specifically where we're at with the competitive solicitation process, which I understood was also of interest. Just to remind everyone, the ISO's annual transmission planning process is a 16-month process that's run annually, so it does overlap. We're starting the one-year; at the same time we're finishing off the previous year. The first stage is the development of the study assumptions, Phase I. Our Phase II process is the detailed evaluation landing on our recommendations and concluding with our request to our Board of Governors to approve the transmission plan and the projects in that plan. Phase III is the annual competitive solicitation process for the projects that are eligible for competitive solicitation.

In the 2012-2013 Transmission Plan, we did identify a number of projects that were eligible for a competitive solicitation. The projects that are currently eligible under today's tariff are policy or economically driven projects, or reliability driven projects that provide additional policy or economic benefits. In the first category, we did identify a Sycamore-Penasquitos 230 kV transmission line as being eligible for competitive solicitation. We're also moving on an Imperial Valley Collector substation and line project that was management-approved, that was considered urgent and necessary to move forward with, ahead of the annual process, so that's actually the one leading the way on the competitive procurement cycle.

We've also identified one reliability driven project that provides those additional policy or economic benefits, and are therefore eligible for the competitive procurement process.

I should mention, reliability projects that are pure standalone reliability projects without those additional benefits remain with the incumbent transmission owner at this time. Those rules do change when our FERC Order 1000 Regional Compliance filing takes effect.

The Phase 3 Cycle is, as we've set out on this chart, has a specific timeline that leads us to the November timeframe, publishing the winners for the two projects, the approved project sponsors, as well as publishing our report on what led us to pick those particular sponsors. And that's assuming that the projects that step forward, the project sponsors that step forward, lead to us being the deciding force.

Under our current tariff provisions, if one siting agency is responsible for the applications of all of the sponsors, it would fall to the siting agency to make that choice.

On this slide, I simply set out an order of the steps that are followed as we move through the solicitation process and the selection of the successful project sponsor for these competitively procured facilities. We follow a fairly rigorous process set out in tariff. One of the other issues is, just to make sure stakeholders are aware, we can talk about the process itself in general terms, but any questions about any of the active competitively procured projects that are in progress have to be submitted electronically and are responses go to all stakeholders at the same time. They're posted publicly as opposed to engaging in one-on-one conversations with interested project sponsors.

That concludes the presentation. I'd be happy to answer any questions on the material.

COMMISSIONER MCALLISTER: Thank you for that. That was very helpful. But no questions, it looks like from the dais? Yeah, okay. Great, thank you.

MR. MILLAR: Okay, thank you very much.

MR. RICHARDSON: Good afternoon. My name is Kevin Richardson. I'm a Transmission Planner for Southern California Edison. Specifically, I work in the Generation and Interconnection Planning Group, that's the group that determines what upgrades are necessary when a new generator tries to connect to the Edison system. I'm also the project sponsor for many big Edison projects. I also worked on the Desert Renewable Energy Conservation Plan's Transmission Technical Group Report.

Now, I've got a lot of material to cover today, so I've got to warn you right now, I'm going to need to get hyper with the IERP. Now, in the event I have some kind of medical emergency trying to squeeze 24 slides into 15 minutes, I want to first leave you with these three key points: 1) Edison is committed to meeting the State's renewable goals in a safe and responsible manner, so much so that we've committed to upfront financing $5 billion of transmission upgrades to provide capacity -- did he just say $5 million? No, he said $5 billion of new transmission projects to provide capacity. And I'm here to say that those upgrades that we're pursuing align with the DFAs that are coming out of the DRECP; 2) even though these upgrades are going forward, there still are a lot of challenges. One of the big challenges we're seeing is that generators complete their studies and then do not sign a Generation Interconnection Agreement. That can have the effect of some projects hoarding capacity of the system from other projects. It can also have the effect of making later queued projects trigger upgrades that may not need to be triggered; 3) Edison realizes the challenges of meeting the 33% RPS and we're diligently doing what we can to try to help out. For instance, to the developers, we try to offer them publicly available maps and also offer the chance to do pre-scoping meetings with Edison, so they can kind of sit down with us and get better informed about our transmission system so that they're not filing generation applications for projects that would just be no-go's right off the bat.

So that said, let's get into this. Now, we just saw this slide from the CAISO, mentioning all the transmission we need to get the 33%. I added just a red rectangle to show that many of these projects are Edison projects, and they're part of the $5 billion of upfront financing that we're doing. Now, regarding uncertainty about some of these projects like TRTP, or Cool Water-Lugo, or West of Devers, I really cannot understand it. Basically, at the CPUC just a couple weeks ago, Edison was up there giving testimony. Chuck Adams and the NPO Project Manager for TRTP said, "Hey, we're going to do everything we can to meet the original in-service date. If we have to hire extra crews, we'll do that." And really, for West of Devers and Cool Water-Lugo, these projects have publicly available project pages on the Edison website, there's a project timeline table that shows the timelines for the outreach activities we did for these projects, when we're expected to file the Proponent's Environmental Assessments, how long we expect the agencies to make a decision, and how long construction will take. I've looked at these websites, I haven't seen major changes in them. So I'm wondering, do people not go to these websites? Because I don't think the dates are changing. For West of Devers and Cool Water-Lugo, we're going to file our PEAs in August of this year. The OD date for Cool Water-Lugo will be still 2018, for West of Devers, it will be 2019, and again, I'm going to be showing in this presentation how these upgrades correlate to the DRECP Development Focus Areas.

I'd like to make a point, though, that the 2010-2011, the 2011-2012, and the 2012-2013 Annual CAISO Transmission Plans state that no other additional transmission projects are needed to support 33% RPS. Now, just before I get into this, just one last comment. I've given this presentation -- this will be my third time -- and I've also done a lot of educational outreach regarding transmission planning, in general, and some of the feedback that I get, or the questions that people ask, lead me to believe that a lot of stakeholders involved with all of this kind of think that the analysis that went into the DRECP Transmission Technical Group Report is the same kind of analysis that goes into the Annual CAISO Transmission Plan, or the Generation Interconnection Process Studies. Well, I was on the TTG Team, I don't think that's necessarily the case.

The other thing I'm hearing from a lot of stakeholders is that there seems to be this belief that there's a secret team of engineering Ninjas working behind the scenes of the DRECP that come up with some, you know, perfect transmission plan to incorporate all the megawatts in the DFAs. I don't necessarily think that's the case, so I wanted to make a little table that shows the type of analysis that goes in the annual transmission plan and the generation interconnection process versus what we did for the DRECP, TTG Report, just so everybody knows. Now we can get into it.

All right, here's Alternative 3, DFA from the TTG Report, over on the right side. You can see all the pink groupings, which would be like the DFA areas where all the megawatts are supposed to develop. Now, green circles are existing substation, green stars and blue stars are part of the conceptual transmission plan that I developed for the purpose of back-calculating what acreage would be needed to address this DFA.

Now, you can see at the top Barren Ridge, Sub 3, then you see Windhub coming down, you see Sub 10, you can see Whirlwind, a little to the lower right Antelope, you can also see Vincent. Now look at the left, here is a map of the TRTP project that's currently under construction, Windhub, line to Whirlwind, line to Antelope, line to Vincent, so there's TRTP currently being constructed right now fits with this development focus area in Alternative 3, and the other Alternatives in the DRECP. So we're building transmission right now that will meet the needs of this DFA.

Now, we can look at the capacity of the upgrade, you know, what was the capacity in the area before? What would the TRTP project do? How many queued megawatts in the CAISO queue are lined up to use this upgrade capacity? And then how many of those megawatts have their studies completed and are not signing agreements for some reason?

All right, so what's the capacity in the area, in that Kern County Area, the Tehachapi Area before the upgrade? Well, as far as Edison transmission, it was really zero. I mean, there was a couple, I think, wind developers out there, they had their own gen-tie line that went all the way to south to our Vincent Substation. Then LADWP has two lines there, one being the DC line, the Sylmar-Celilo.

All right, so we recognized the need to build some transmission out there, heavy interest from the wind community. So, you know, there's a big study process and we come up with TRTP to handle 4,500 megawatts. Here is the CAISO queue, I believe this is the most recent one, posted on 5/1 with a date of a 4/30/2013. If you take it and you sort on the utility column all of Edison, then you sort on the station or transmission line, of all the substations that would input power into the TRTP, so it's

Antelope, Whirlwind, Windhub, all of those. That's 6,822 megawatts that would like to make use of this upgrade.

Now, if you look at the last column on the right, it says Interconnection Agreement Status. That's if they signed a GA or not; if it's executed, they have, if it's in-progress, they haven't. I've got it color coded, red for old serial projects when we used to site them one at a time; then, when we went to transition cluster, you've got that orange Cluster 1 is brown, Cluster 2 is blue, Cluster 3 is green, Cluster 4 is the white arrow. If you add all that up, there's 2,933 megawatts of generation projects that have studies completed, that are not signing GIAs.

And if you want to know the dates of the queue clusters, the Cluster 3/Cluster 4 queue cluster got the reports in November of 2012. The Cluster 1/Cluster 2 Phase II people got their reports in August of 2011. The Transition Cluster Phase II projects got their reports in August of 2010. The Serial Project happened all before that.

Now, you're supposed to sign your GIA within like 90 days, I think, so if you want to go through the hypothetical exercise of saying, hey, you guys haven't signed, they're languishing in the queue, you know, what if we flushed them out of the queue? You subtract 2,933 from the 6,822 that gives you 3,889 megawatts. Well, you know, that would mean that TRTP would still have a capacity of 611 megawatts, so TRTP could still serve this area if the queue was cleaned out.

I can go through a couple different areas. The Riverside East Area, what Edison calls the Eastern Bulk Area, at the top you can see the map for the DCR, Denver, Colorado River, and West of Devers. Below, you can see the Alternative 6, DFA buildout, you can see the Blythe pink DFA. Well, we're currently building transmission right now, the DCR line, that would serve that area, and we're proposing the West of Devers project add additional capacity. Let's take a look at what the capacity was before, what it will be after, the DCR plus West of Devers, how many people want to use that area, and how many people haven't signed agreements.

The capacity in the area, well, we had one big 500 kV line, the Devers-Palo Verde Line, that's rated at 2,300 MW, there's some flow on that line, but for the purposes of 15 minutes, let's just say it has capacity of 2,300 MW. DCR and West of Devers will take that 2,300 and turn it into 4,000 MW of capacity. How many people want to use that? Again, sort on Edison, sort on all the stations and transmission lines that would inject power into that corridor. It's 5,230. Well, how many people haven't signed agreements? 1,965. Now, if you do the math on that one, you know, DCR West of Devers would still have some capacity. But what I really want to call out on this slide is look at the queue position called out all the way on the left, Queue position 1, entered into the Generation Interconnection Agreement process in 1998, still hasn't signed a Generation Interconnection Agreement, that's 15 years. People: I was still in college. What in the -- you fill in the blank -- is going on here?

Now, we can go through a couple different areas, EITP Area, you know, on the right you can see where the pinkish DRECP's DFA is. Again, we're currently building the El Dorado Ivanpah Transmission Project. What was the capacity before? It was just a weak 1 kV line, 82 MW. Well, what will it be after when it's completed this year? 1,400 MW. How many people want to use it? 964 MW. Well, this area is actually not that bad with people that haven't signed agreements, so there is still some capacity there. Looking at Cool Water-Lugo, you know, there's a big DFA in the Barstow Area. You know, our line would start there and tick that up. What was the capacity before? Well, the capacity in this area, since this line will help the South of Kramer, the Kramer Area, and also the Lucerne Valley Area, a little complicated, we'll take it step-by-step; for the Kramer area, there's a lot of generation that gets bottled up there and needs to get exported south, well, the lines that do that, there are four lines that handle about 1,120 MW. But if you look at the CAISO plan for the last couple years, there's 1,624 MW of existing generation, so even when you subtract the load, I mean, we're basically at capacity today. In the Lucerne Valley when people want to connect into there, you know, the Lugo-Pisgah 1 line is usually where they're trying to interconnect to. That has a rating of about 275 MW. Well, the project we're proposing would handle 1,000 MW. You know, we've currently got 856 MW in the queue. Yesterday, I got an email saying there's a single project, 875 MW that just requested interconnection in Cluster 6. Now, there's a few projects that haven't signed Generation Interconnection Agreements, but it seems based on the new project coming in, yeah, we would need even another upgrade beyond the South of Kramer or the Cool Water-Lugo upgrade. But still, we're serving that area.

The Lugo-Pisgah project, again, there's still a lot of DFAs in that Barstow Area. Our existing Lugo-Pisgah project would basically help serve that area, as well. What was the project capacity before? The existing Lugo-Pisgah 1 and 2 lines. Total capacity of about 550 MW. What would the project do? It would take that and turn it into 1,400 MW. How many people are queued there? Again, sort the CAISO queue: 1,790 MW. Well, how many people haven't signed agreements? Well, 800 MW. Well, that's kind of sizeable, so, you know, if you flush them out this upgrade could still have capacity after it went in.

Now, let's summarize all this. Let's look at all those upgrades on the left, what was the pre-project capacity in the area? 3,207. What was the project capacity or what will it be after they all go into service? 12,300. Subtract the two. Edison is providing about 9,000 MW of capacity in these areas that align with DFAs. Why is that important? Because the CAISO just said we only need 10,000 to hit 33% Renewable. So we really feel that we're kind of doing our part to help meet the 33%.

I'm running out of time, so I'll skip this one. We all knew the queue is so over impacted, blah, blah, blah, you know, 25,000 MW, and our peak load was 23,000 MW, apparently we could be 100% renewable if we wanted to. Anyway….

This chart shows that, hey, 93 projects have had their studies completed and they're not signed agreements. That's a total of 8,539 MW. This is creating a big impediment for other projects that are trying to go through. And it's creating unrealistic study results. So what are we doing about this? Well, on October 18, 2011, the CAISO put out a technical bulletin called Generation Interconnection Queue Management, and to partially quoted on the first page, "It's the process that CAISO will seek to remove projects from its Generation Interconnection Queue that cannot demonstrate continued viability." Well, is this happening? I'm sure they're trying, but, I mean, you can see from the queues that it's still the current queue, there's a lot of projects that are languishing, and just to be fair, Edison has its own queue for projects not requesting interconnection to CAISO controlled facilities, but to the lower voltage ones where the GIA would just be between Edison and developer. We have that queue. Are there projects that are lingering? I'm sure there are. Could Edison do a better job of flushing that? I'm sure we could.

But as you can see, the mechanism to try to get them out of the queue is very difficult, and as I've heard even the CAISO say before, it often leads to like litigation and, really, no one wants that. So it's very difficult to get people that are stuck in the queue out of the queue. And one of the reasons this is such a big problem now is, you know, we just heard Neil Millar talk about the GIDAP process, kind of how it works, well, it's kind of changed, so now, if you have these projects hoarding capacity and they're making the next cluster study trigger some huge upgrade that's hundreds of millions of dollars, yeah, they've got two choices, B) pay for the whole thing, which historically hasn't really been happening, I mean, developers seem to be able to pay for their project and the generation tie line from their project to the nearest host utility's substation to interconnect, and even to equip that substation with what they need to lay on that gen-tie, but beyond that? We haven't seemed to be able to upfront finance upgrades that are like $500 million, or $2.2 billion, it's just not happening. So then, okay, what can they do? They can select Option A that says, "Okay, well, I don't want to pay, but I want to connect, can you just rank me based on milestones or other things?" But if you really look at a lot of the host utility systems, there isn't a lot of spare capacity right now, so we've created a situation where a developer triggers a big upgrade, they can't pay for it, they want to request this musical chairs situation to try to fit on the system based on whatever system capacity is there, but, again, the last three CAISO transmission plans, no new upgrades are being approved beyond what's needed for 33%. How can we really expect there to be this existing capacity? So, I mean, are we saying that in certain areas they're kind of just going to be shut down because, A) -- I mean, because B), they're not going to be able to afford the upgrade? Or A), there isn't any spare capacity for them to even be ranked on at all? I mean, that's something we really need to look into. In addition to that, there's additional challenges. You know, proximity to transmission facilities is not guaranteed transmission capacity.

I'm really happy to hear sun power, that when they're siting their projects not only do they try to get near a transmission facility, but one that actually has capacity. Hey, great job to the sun power.

The existing Grid was designed to serve customers, not generators. Well, what does this really mean? Well, to me it means, why would you expect an existing utility's Grid to have thousands of megawatts of spare capacity? That would really mean the utility all along was secretly gold plating their system at Ratepayers' expense. I mean, the annual transmission plan is basically to serve load growth. If you look at the 10-year load growth, yeah, it's going up a couple megawatts every year, so, yeah, it's a positive increase, but if you look at what's happening in the Generation Interconnection Queue windows, it's not a slope, it's like a vertical line. So, you know, it's very difficult, and these transmission upgrades can be very expensive, take a long time, the new renewable generation doesn't always replace the non-renewable because of intermittency issues, or because it's not locating to the same area, the host utilities, their bids need to operate reliable all the time, any combination of renewable, nonrenewable, intermittent, non-intermittent, importing, you know, producing in your service territory, whatever the case; the bill says the host utility, there's a problem? You know, people are going to be mad at the host utility.

Multiple generators pursuing interconnection into the same substation can challenge County franchise distribution and also underutilized substation capacity. That's kind of like the Kern County gen-tie congestion issue, you've got so many projects trying to get to the same substation that they start to land lock each other out. So even if you have a viable project, you can't even physically get to the substation, and then the host utility will ask the CAISO, "Hey, approve a new substation," and the CAISO will say, "Did you fully utilize the one you have?" And we'll say, "No, because they can't get to it." And you say, "Well, sorry, you didn't fully utilize it, so we can't approve it." And you're in this like endless loop.

Again, the Generation Interconnection process, it's constantly changing. We went from a serial process, studying them one at a time, to doing a transmission cluster, to grouping them, to now this GIDAP. You know, projects that are serial, they're still under the serial rules, projects that are transition clusters, still under transition cluster, now we've got this whole GIDAP thing, really confusing. The Generation Interconnection process may also produce upgrades inconsistent with prudent long term planning. It's so difficult for generators to get through the generation interconnection process that you start to get this mindset of, "Oh, let's just approve or trigger the smallest possible cheapest upgrade to get them through, even if the next cluster is going to come around and tear it down and rebuild it for whatever that cluster needs to do, just so we don't look like the impediments of 33% renewable power." So you have this like band aid fix of upgrades being triggered, which may not be good for long term prudent planning or for, you know, environmental disturbance issues. And again, the traditional 10-year planning window also challenges prudent long term planning. If upgrades are taking 78 years to build, you're only planning for a 10-year window, you've only planned for like two to three years.

All right, so to help developers out, we've tried to come up with these system maps, color coded for like red, hey, it's really constrained, we can't tell you no, but if you try to develop there, it's going to be really expensive and trigger long term lead time upgrade. In areas that are green, that still might have some capacity. If those maps aren't working that great, we'll even say, "Hey, you can call us up, call this number, send this email, we'll do a pre-scoping meeting with you." If you want to know, "Hey, can I interconnect in this area," eventually you can work your way to a transmission planner like me, we can go over, "Hey, that line has certain capacity, you know, maybe you can handle this much, or maybe if you try to develop 500 MW, you might trigger this kind of an upgrade." So you can get a sense before you just blindly submit an application that it may be a no-go right off the bat.

So to summarize, transmission to support the 33% RPS, it's approved, it's underway. You know, we think some of the Edison ones will give up to 9,000 MW of capacity, we're upfront financing a lot of moolah for this, approved and proposed transmission has a high correlation with DFAs that we just saw. Yeah, the Generation Interconnection Queue is oversubscribed, nothing new there. Generation Interconnection Queue oversubscription creates challenges for all. The CAISO queue reform efforts are underway. Further reform may be needed to facilitate timely renewable development. Transmission capacity and constraint information is available to developers and they can always give us a call, we'll sit down and chat with them. So I want to thank you for your attention, your time, and also your tolerance because, you know people, I know when I talk about this I can get all excited. So I hope you stuck with me. Any questions?

COMMISSIONER MCALLISTER: I was thinking some play of words that was along the lines of your hyper for the IEPR, and I just came up empty, but I was hoping something related to yoga or stretching or something like that. But anyway, just to compensate. But thanks for that. I guess I would sort of challenge some of the panelists coming up to -- you've got prepared statements and everything, but to the extent that the interaction with the utility and the queuing issue is difficult, I think -- or at least, you know, there's a tendency to sort of say, "Oh, the problem is the utility." But I think that obviously we have a really complicated ecosystem here and there's lots of issues, and that's why there's several different layers of things going on to try to get some rational approach in place that folks can work with and engage with and get done in a reasonable amount of time. So anyway, I won't hold things up, but I am looking forward to the other angles on all of this.

MS. GRAU: Just a few notes on the roundtable before we begin. Mark Hesters, our Moderator, will give more instructions, but for those of you in the room and on WebEx, and for our Commissioners on the dais, I just want to note a few items here.

Joe Desmond or Designee, we actually have the real Joe Desmond, so that's good. Bob Dowds, who will be talking about Westlands Solar Park is here via WebEx. We know he is on the line, so Mark will remember, yes, to defer to Bob after Peter speaks.

Diane, I apologize, we actually have you on the hard copy agenda as Diana, we fixed it on our WebEx, and we know you are Diane. And then Will Spear and Jamie Asbury are on the same plane, which was experiencing mechanical difficulties, they will not be here this afternoon, but I understand that Tony Braun can fill in a little bit for Jamie Asbury. Is that correct? And just for those of you in the room, we do have a handout from IID, as well as for Tony Braun, they won't be speaking here at the podium with slides for those of you in the room, but you may want to follow along with Tony's remarks with his handout.

And so with that, I will turn it over to Mark Hesters. Thank you.

MR. HESTERS: Good afternoon, Commissioners, panelists, and everyone else in the room. I was going to invite Carl and Ali to move over to the far end of the table so their backs weren't to the dais. But Carl fled. When he gets here, we'll invite him, he can move if he wants to.

Our general guidelines for the panel, everybody has five minutes to make some prepared remarks, then we'll take -- after each panelist, we'll take questions from the dais, and then once we've gone through everybody, we will hopefully have some time for kind of bouncing back and forth if there's some interaction that needs to happen at that point. Then we'll take questions from the room.

So let's start with our former Chairman, Joe Desmond.

MR. DESMOND: Thank you, Mark. First let me thank the Commissioners for giving me the opportunity to speak here today; I think I want to thank you for being first, but we'll see how the questions go afterwards. Also, I want to thank the previous speakers, as well, for such a content rich and well researched set of presentations. And someone has referred to my presentations as sticking 10 pounds of potatoes in a five-pound bag, so I appreciated the last SE presentation, in particular.

So I was asked first to speak to some of the issues with respect to Hidden Hills from the perspective of a generator, and then I'll go into specific recommendations. I will follow up my comments in writing for the record so you have those. Regarding Hidden Hills, when we had suspended that project, it was with respect to uncertainty regarding the timing of certain transmission upgrades, and one of those uncertainties, for an example here, was the reroute of the Lugo-El Dorado 500 kV line. That line was required for -- or I should say "needed" -- the reroute needed for supporting deliverability of renewable generation in multiple renewable zones, including El Dorado, Tehachapi, Nevada C, and Imperial Valley, and needed for all 33% Renewable Portfolios estimated in 2015. The scope, though, required dismantling and rerouting approximately six miles of line in order to avoid being a common mode contingency for lines that were within 250 feet of the center line. So the cost of that, I think, was $30 to $40 million, but there were so other considerations, those considerations dealt with a new substation looping, the NQC reduction, a special protection, congestion management, pursuing a temporary waiver, but ultimately that was, as I understand, moved into the TPP. But it was an 84-month lead time, and so the interim solution was actually not factored in from a generator's perspective on the firm things that we have to account for when you're thinking about financing, until it was after that process. So that's just an example of how the synchronization is absolutely critical.

I'll make five key points with respect to the synchronization challenges here, and I do know and recognize that all of the parties really strive to work hard to ensure that we're accomplishing the policy goals.

But this challenge is certainly not new. Not since the restructuring of the electric utility industry and really brought into perspective with the RPS 20% and then later 33%. And so it's stating the obvious to say that the lead times for transmission development is longer than generation development, with the average lead time to permit, engineer and construct new 230 and 500 kV lines between five and 10 years, respectively, outside of the two plus years of studies that typically are involved; whereas, depending on the type and the size, development cycles for new generation tend to be shorter.

The issue is not necessarily the difference in timing, but rather the uncertainty within both processes that result from different jurisdictions, whether it's FERC on transmission rates, terms and conditions, or the different State agencies that are responsible for resource procurement, transmission and generating permitting.

So from a generation developer's perspective, the procurement, development and financing processes would benefit from greater certainty than can be provided in the current process, both interconnection and permitting, and ideally looking to converge the processes, both long and short term. And I was struck by Lorenzo's approach to allowing that incremental connection and thought there might be actually some ideas that could be borrowed from the EIM application to account for new generation projects coming on line, it's well worth researching because I think he accurately described the problem as, you know, how do we get to a critical mass to cover those upfront costs of those projects, recognizing that there are all these changes?

The second point is that the consequences of delays in transmission upgrade completion are unbalanced between generators and PTOs. For Developers, there is certainly an urgency for completing the transmission upgrades in a timely manner, and developers can only plan their schedules around the study provided transmission project lead times, even though shorter timeframes may be realistic when considering the over-conservatism, or alternative upgrades that could be pursued. Sometimes commercial commitments need to be made before this information is finalized. And identified upgrades in the lead times associated with these upgrades are a continually moving target through the Phase I and Phase II study process, as well as the various REAT studies. In addition, there are often forecasted delays beyond the stated lead times or upgrades, especially for major new lines, and there is discussion, but not necessarily a formal institutional process, to identify these short-term alternatives to provide interconnection service to generators in need when these major upgrades are delayed.

Generators may be at commercial penalties or termination, at the worst, if transmission timing cannot be made to align with generation time and requirements. There is not a commensurate incentive for PTOs to meet the timing requirements. And so, as a recommendation, to the extent the State finds it in its interest to advance its policy goals, it might consider benchmarking or accountability for cost and timeliness of upgrades, as well as additional FERC perhaps, or just incentives for successful performance, and/or penalties for successful performance and/or penalties for underperformance. So that's number 2. Number 3, and give me the one-minute sign so I stick to the schedule --

MR. HESTERS: You actual have until 3:15.

MR. DESMOND: All right, thanks. The CAISO and

PTOs should identify transmission solutions that meet the timing needs of generators, that's sort of recommendation 3. Here, the perspective is that the identified transmission upgrades in the Interconnection studies do not necessarily align with the timing of generation development, and parties should be encouraged to use all solutions available. I gave the example of that six-mile, 84-month reroute from El Dorado where there were interim solutions that could have been done, and yet the necessarily conservatism there, it just fell outside the timing of the process.

So rather than necessarily only proposing the PTOs ideal or default upgrade, solutions could work backwards from the time they need to propose upgrades that align with maintaining reliability. And again, this is where I was struck by Lorenzo's approach to the EIM that allows this sort of incremental addition, and yet accounting for flexibility, and there are some parallels, I think, that could be drawn there.

Number 4 is the transmission process has not always aligned with the Investment Tax Credit expiration. This is a temporary issue, but just to be aware that the planning process should recognize that there are many generators interested in coming on line prior to that 2016, and our recommendation certainly is to pursue all the alternatives to ensure those generators can qualify for that, as benefits ratepayers, but more importantly to encourage California and the Western States to strongly support Federal legislation for ITC to qualify for a commence construction eligibility, which would ease some of that burden, meaning PTC and wind qualify for a 5% safe harbor commence construction, large scale, whether it's CSP or PV projects -- for that matter, distributed wind -- also would get under the ITC a 5% commence construction eligibility.

And lastly, to the extent that transmission planning process sometimes under-recognizes existing commercial commitments in place between utilities and developers, which can at times undermine the ability of transmission to develop. And here I'm simply trying to describe that the TPP is an iterative and self-fulfilling cycle. So as an example, for the benefit of the CAISO TPP, the PUC/RPS Calculator Forecast Resource Portfolios are based on a variety of criteria, most notably highly weighting only those projects with PPAs or that have achieved certain permitting milestones. Projects with PPAs and on line dates farther in the future are often not as far along in the permitting process by design. However, these projects that may have been better positioned to match the schedule of longer lead times transmission are systematically underrepresented in the RPS Calculator, thereby reducing the chance that needed major transmission upgrade would be identified and initiated in the TPP, and that the contracted project would be able to meet its commercial obligations.

So again, I would simply close by saying the short term transmission planning needs to the extent possible should align with the commercial interests to actually reduce the risks that the transmission would be underutilized and longer term transmission planning should contemplate both the technology and policy objectives. Thank you.

MR. HESTERS: Any questions for Mr. Desmond?

COMMISSIONER MCALLISTER: Thanks, Joe. I appreciate that. Any questions? Thanks for being concise.

MR. HESTERS: Next we have Peter Weiner with, actually, Abengoa Solar.

MR. WEINER: Thank you very much. Commissioners, it's great to see you here today and I want to echo Joe's thanks to you for all of your efforts on this and those of the previous speakers, as well. I'm going to try not to speak quite so fast or state quite so much because I'm sure I don't have as much to say.

But just to start out with, I was thinking about this a second ago in terms of your role because so much of what we're talking about today is an ISO role, or a PUC role, and yet it's the Energy Commission that often approves the projects, at least the ones that are thermal, and not all of them are, and that has had a significant role in thinking about where development should take place. That's the whole DRECP concept, among others.

We are in a transition in many ways over the last 10 years between conventional sources of energy and renewable energy as a policy of the State, and nowhere in the country or the world is the policy of the State so heavily toward renewables, for climate change and other reasons, than it is in California. But that means necessarily that it is difficult, especially with large-scale renewable projects, to build them where the transmission already is, and the transmission planning becomes more and more important.

So now we have policy-initiated transmission, but we are in a transition from generator-initiated transmission; that is very difficult for us in terms of regulatory authority to figure out how do we get done what we need to get done. What we've done in the past is we've had the ISO approve of certain transmission, we've had the PUC in a role that approves a certain transmission, the Energy Commission in that sense has had a more avuncular role, I think, and what we've done is counted on the PTOs to build it because there's money in it, and we assumed that they will. But it doesn't necessarily happen in a synchronous way with the renewable energy generation that we've approved. So I'm here today representing Abengoa in the Mojave Solar Project that was approved by this Commission with the able assistance for Abengoa of Chris Ellison, who is here today, and the Energy Commission approved the AFC, and the PUC approved the PPA, there is an LGIA, so we're not in the basket that Kevin Richardson talked about of people who haven't signed up. And this is a project where the PPA is with PG&E, and the transmission relies upon Southern California Edison. Well, therein lies some issues because what Joe referred to as the lack of balance and the consequences of not getting the transmission would fall heavily on Mojave Solar Project because they're relying on a special protection system at the moment to generate and meet DITC deadlines, but if they don't get transmission in place by the on line date of 2018, they will soon thereafter incur incredible penalties that could put the project out of business. So we really need that.

Today we heard from Kevin that they will submit their PEA and the CPUC in August of this year, but for some period of time there was enough uncertainty that BLM, which will have something to do with the gen-tie, and the PUC put off signing a Memorandum of Agreement to deal with the NEPA-CEQA consequences because, oh, no, it's not going to be filed until December. Those kinds of delays are not one that Southern California Edison created, but it had an impact when no one was sure. So these kinds of delays can ultimately delay the on line date because it is not only the PTO building it, they have to get approvals. And if those approvals are delayed because people misinterpret signals, or there's uncertainty, we all have problems. And although the transmission owners have a good faith obligation under the Transmission Control Agreement that they sign with the ISO to in good faith build it, there are slips along the way, there are uncertainties, and there are not enough tools in the toolbox. And Joe referred to some of them that you might have in terms of accountability and penalties, but I don't know that you have them now. I don't know that the PUC or the ISO has them now. They may, but I don't know that they're used. And it's hard to use them because if you say you have to meet X date and people meet the date, but they have an inadequate document, oh, now what? So there are -- and that's one of the reasons people don't want to submit until they do have a good document, because they don't want to be in that position. So there's enough issues on all sides of it, but there's such a dysfunctionality in terms of coordination that I just would say to you, we need more tools, we're very pleased to hear today, by the way, that the CPUC will be filed in August, but we think there needs to be more transparency, more milestones, more reporting, so that these kinds of things happen in a way that doesn't create large delays. Here, the delay was not large, by the way, I'm not saying that, I just said that there was some uncertainty. But these dates are critical for the generators, much more than they are for the society at large, or for the transmission owners, and so we just need to do something to try to make that a better process. One more thing, if I can take one more minute. In this particular instance, it is possible that there is in our American system a competition with regard to the transmission line, and we understand that the ISO is evaluating that as an alternative that might be looked at in the CPUC proceeding. From a generator standpoint, it's not that we are taking sides, or have a preference, or whatever, what we're concerned about is the delay that this process can cause because if you have a contested proceeding before the PUC because people are competing with each other, and there's no fast solution to that, then we who have penalties looking at us in the face are the losers. So, thank you very much.

COMMISSIONER DOUGLAS: Well, thanks, Peter. Let me just ask a brief question. I mean, you've raised some very important issues, and they're issues that we've faced time and time again, especially in the era of ARRA projects, and of course Abengoa is one of our ARRA projects, where we have tight deadlines and there are a lot of actions that need to be taken by a lot of different parties under tight time constraints in order to really put together the series of actions that are needed to allow a project to meet an on line date. Do you have specific suggestions for how we might do more, the Energy Commission, for example, or the Energy Commission in concert with other State agencies, or State and Federal agencies, to make this a smoother process? Because what you're saying is absolutely right, no one feels greater urgency in meeting the on line date than the project developer whose project is hanging in the balance of all of these things, and as the State, of course, we -- and I use "we" broadly -- we, the ISO, the PUC, and the agencies involved in this, the broader State and Federal agencies partnering in REAT, and REPG, you know, we have done many things to communicate more and to have more transparency and provide developers a forum to come in and talk to all of us together, or whatever is needed. I'm interested to hear what more might be done, or how we might approach this sort of thing.

MR. WEINER: Thank you, Karen. I didn't script this one. I think my perception of the incredible success of the REAT and the REPG during the ARRA process was that there was an unprecedented amount of cooperation between State and Federal agencies, but also unprecedented cooperation among State agencies. And one of the things that I'm told occurred, since I wasn't usually allowed in the room, was that you all met on a every two week basis, if I remember correctly, and at one point or another you were going project by project, what's at issue, what's the critical path to get there, how do we do it. And you talked with each other about it. I think on renewable energy projects that are situated where they've already been approved, and in Abengoa's case for example, are under construction with 830 jobs at stake, you don't want them to finish the process and only be able to turn on a large light bulb, it's just not a good idea. And what it seems to me is that you could take those projects, or the projects in the I-10 Corridor, for example, that are a lot of them within the SEZs and within the DFAs of the DRECP, and say what are we looking at? What are the issues of congestion? Who is dropping out? Who is coming in? In other words, get down to a very granular level, but on an interagency basis. And I think the Commission is well respected at the table with the ISO and the PUC and I think that you have often had the support of the Governor's Office, and the PUC is a little bit more separate from the Governor's Office, and so is the ISO, so I think that's been helpful because some problems can get solved that way, not all of them. But having that kind of project-by-project, what do we need on the transmission side to make these projects go, that are being approved, or have been approved, that are in the priority list line, or whatever, I think could be very useful. And I don't see that -- I don't know that that's happening right now.

COMMISSIONER DOUGLAS: So that's very helpful because what you're suggesting is a continuation of something that's occurred, but at the same time it may be necessary to make sure that we keep it up, and in particular the problem solving around specific projects. I mean, to the extent -- of course, that door is open and has been open, but to the extent that you see projects like the Abengoa project, for example, where some of that is necessary, you know, you should definitely bring it to our attention. I should say, just with the siting hat on for a moment, that of course where projects are jurisdictional, the Energy Commission Commissioners don't get to sit in the room when such conversations occur, but the conversation between State agencies to manage a proceeding, or in general about issues that are not at issue in the case, those do and have occurred, and that kind of coordination is really important.

MR. WEINER: Well, if I may just say one more thing. There are projects that have already been approved, where you can sit in the room --

COMMISSIONER DOUGLAS: That's right.

MR. WEINER: -- and there are PV projects and wind project where you can sit in the room.

COMMISSIONER DOUGLAS: That's right.

MR. WEINER: But even for thermal projects that are for the Commission, to the extent that you're not trying to be pre-decisional about whether a project is going to be built, but simply looking at things that are in the planning stages, and might be, you still I think need to plan for the transmission for those projects. And there's no way that we cut corners, we agreed all along that in ARRA projects we wouldn't cut corners, but we would try to go faster down the same track that we were going. And I think on these projects, given the enormous lead time for transmission, we're talking eight years and five years from whenever, I mean, they're long. Given all that, we can't willy nilly think that we're going to get anything like 33% actual generation if we can't connect it.

COMMISSIONER DOUGLAS: That's right.

MR. WEINER: So it may be a little bit of a reprioritization is what I'm saying of what the REPG and the REAT are doing -- and I think Janea has to help us get a replacement for herself in D.C.

COMMISSIONER DOUGLAS: We're all waiting for Janea to come through on that one, but we're delighted to have her here, so we can't complain too much. Thank you, Peter.

MR. HESTERS: Actually, we're supposed to go to the WebEx next, but I wanted, Carl, while you were out of the room we actually had a flight issue from San Diego, so a couple people aren't here. If you want to move over there so you don't have your back to the dais, you're welcome to do that.

So our next panelist is Bob Dowds. He's representing Westlands Solar Park and it's over WebEx. Bob, are you there?

MR. DOWDS: Hello, this is Bob.

MR. HESTERS: Now we hear you. Go ahead.

MR. DOWDS: Oh, perfect. Good afternoon, Commissioners and members. First off, I wish that I could say that we are hyper for the IEPR, but we have been involved in this process since 2009. I do want to state that we are not (indiscernible) and water users within

Westlands Water District. It started off being involved in the RETI process in 2009. At that time, through the Renewable Energy Transmission Initiative, Westlands CREZ was established within Kings County and it was allocated, I believe, at the time nearly 5,000 megawatts of capacity, for discussion's sake. More important, however, is the fact that within the district we've had 90,000 acres in drainage impaired ground, which we have purchased another district (indiscernible) for higher and better use, or to have the Federal Government to complete its (indiscernible).

MR. HESTERS: Bob, your voice is breaking up a little bit. I don't know if it has to do with distance from the microphone or something, but it's a little bit muddled on this end.

MR. DOWD: Oh, man, I'm so sorry about that. Hopefully this is better. If it's not, then I will just submit my comments in writing. So, Commissioner Douglas, please let me know.

COMMISSIONER DOUGLAS: That was much better.

MR. DOWD: Okay, excellent. So I do want to just echo a couple of things that I've heard today, 1) we agree and we hear on a continual basis from project developers and utilities alike that there's a need for certainty, and the reason why we got involved with the

RETI process was it really, I think, drove a solid balance of policy driven goals, economic opportunity, and reliability, which of course then needs the long term prudent planning. And I would like to suggest that those discussions regarding permitting and construction transmission and generation be handled at the same time. So those are some high level comments. And then I will submit the rest of our comments in writing to the Board.

MR. HESTERS: No questions, it looks like. Thank you, Bob. And next we have Renee Robin.

MS. ROBIN: Is that on?

MR. HESTERS: Yes.

MS. ROBIN: Hi. Thank you. I'm Renee Robin with SunPower Corporation and I am the Director of our Permitting Operations. And I would say off the bat that I'm treading water way outside my comfort zone, but I'm going to give it my best effort.

There are a couple of people I want to thank and I would also recommend to the Commission that you engage in getting input from one, is our Director of Transmission, Alan Colmes, who has been involved in these issues for a very long time and I think he has some really important insights on this. We were hoping he could get in on WebEx, but he's in transit right now. The other person I'll mention, who is here, I believe, still is

Rachel Gold from the Large Scale Solar Association, she's been doing pretty deep thinking about these issues and her input to me has been very helpful.

I think that I want to echo to start off that the issue of demand versus policy-driven transmission is very very important at this stage of the game, and if we're going to stay in the kind of cluster approach, we're going to have cost allocations for the renewable energy developers that are going to continue to make projects infeasible, are certainly highly difficult to move forward.

And I also think that I'd like to focus a little bit on the relationship between the procurement and the transmission timing because, without a transmission schedule that aligns with contracts and COD, we're unlikely to have projects that are financeable, and this is a huge issue for us. I always am wondering what is the chicken or the egg here? Do we get our PPA first? Or do we do our LGIA and put all kinds of money on the line, and pray that that's going to be compelling enough in the procurement policy to get what we need? It's a very high risk game for us and we're trying our best to -- and when I say "we," I'm talking about all of the large scale renewable developers.

And I want to say thank you to Kevin for sharing some really compelling information. It doesn't necessarily seem like that's what we're seeing on the field, so to speak, and I think that the reasons why LGIAs may not have yet been executed in many instances are part of the same dilemma of when do we put the money on the line. Many of those LGIAs are in heavy negotiation, but I still think he makes a good point that there's quite a bit of fallout that would occur there, and so there is some residual capacity. But nevertheless, I think that I wouldn't want to assume because the LGIA is not executed on these slides that those projects are not going forward, so I just wanted to mention that.

There's three areas in the state where we've all been working very hard, the California Desert, Imperial County, and then the Westlands Water District area of the Central Valley. And when I think about have we succeeded in getting what we need to make those areas of the state proceed for solar, we are making great progress. I think the story of Westlands is particularly disappointing to me. I really think that we had a policy mandate in the state to look at disturbed land that didn't have the same kind of issues for cultural resources, endangered species resources, with high solar capability, and the projects are not happening there because the transmission is not happening there. And while there are some things on the schedule going forward for the one line, that's not anywhere near making the industry focus on that area instead of other areas that are highly problematic.

I think also a couple people have mentioned the 2016 ITC, and I think we have so many projects that are going to be seeking to interconnect, or they're going to lose their ITC eligibility before that time and we're going to see a real compression of not being able to meet those deadlines, and as Joe mentioned, that's got a Ratepayer impact, but also has an industry impact, projects that would be financeable may not be financeable, and so we start to lose industry in the state.

So I think those are the main points I wanted to make right now and I'll defer my time to Carl Zichella.

COMMISSIONER MCALLISTER: I do have one question.

MS. ROBIN: Sure.

COMMISSIONER MCALLISTER: I'm sure Carl can take you up on that, right, Carl? Anyway, I do have one question. Do you sort of look at the looming ITC change as potentially another kind of crisis point? Or sort of a moment that focuses all of our attention so that perhaps we can replicate the roll up your sleeves, get in the same room, maybe it forces us to do something like that to approach this in more of a SWAT team kind of approach like with the ARRA funds? I mean, do you see it at that level of crisis?

MS. ROBIN: I do think it's critical and I think it's part of a package. What we're hearing is that we -- and the solar industry needs to be cost competitive and we are trying very hard to get there as quickly as possible without any kind of incentive programs, but when we look at what is piled on top of the costs of development of these projects and the transmission elements, and you also tie that with where we are, how close we are to trying to get to good parity, every penny counts. And that's more than just a penny, I think it's a really important part of the equation, and I do think that we should look at trying to get what Joe had mentioned, it's certainly about being able to have the safe harbor provision, for sure, and also to look at possible extension of that timeframe.

The other thing I didn't mention before is that on the permitting side we've tried to partner with our customers where, when we are doing our project applications and our Environmental Impact Assessment, we're often the first in line for an area where a reconductoring and an upgrade needs to occur, and so we take in many instances the inclusion of those elements in our project description and in our Environmental Impact Assessment, our EIRs, and then that EIR is done in a fashion that is suitable for the CPUC to make use of, we hope, we try very hard to make it be adequate for that purpose, so that it will shorten the huge amount of time in the process. And if we do it right, then it can go directly from the granting of the conditional use permit and the certification of the EIR to the CPUC to do its work. But then we come to the time when, okay, whether it's a CPCN or an NOC, that's all granted, we're ready to go forward, and then we look at the construction schedule for those transmission upgrades and they are way longer than what our PPA, COD requirements are, and so we are in a financial pickle right off the bat. So we need to think about what we can do to try and help make that go faster, whether it's competitive bidding on some of the construction, or other items like that, to be able to match together what the PPA requirements are and what the timing is for the upgrades.

COMMISSIONER MCALLISTER: Thanks.

MR. ALVAREZ: Good afternoon, Commissioners. Manual Alvarez with Southern California Edison. I won't be as hyper as Kevin, I've been through a couple of these IEPRs, so what I like to remind you about is to keep initially your high level of responsibility, we're here before an IEPR committee and a State planning process that takes place, and so there's some lessons that I'd like to share with you and some observations that I'd like to provide for you, so that you can actually do some deliberation and consideration as you think about the issues you're going to draft and the policies you're going to recommend to the State as we go through this process.

First of all, Edison has come before you in the past and argued for comprehensive land use planning effort. The DRECP is in fact that example in terms of its practicality before us today. So we actually would like you to continue that activity and actually do an exercise in which you can examine the coordination and the functioning that took place during that process. You have two individuals, Commissioner Douglas and now Commissioner Scott, who can actually put some real life experience on what the coordination actually really meant between the State agencies and the Federal agencies, and how you got through that maze. Now, if you can help clarify what that maze looks like, I think that's an accomplishment during the IEPR process that I think everybody at this table would be looking for, so I'll challenge you to kind of consider that.

The other thing is that DRECP could actually serve as, what I think I'm hearing, at least initially, that's missing in California and that's the regulatory framework we're all looking for. What does that consist of? And I'm going to ask the Commission, the Committee specifically, to perhaps look at your past, look at your history of your own agency how you dealt with the land use issues during the early years of the Commission for power plants, and how you're going to bridge that over into transmission. Definitely a synchronization between transmission and generation is probably far more important today in going forward as it has in the past, so it's definitely something where that coordination is key.

Your Project Manager, Suzanne Korosec, is probably tired of hearing from me about the need for coordination between the agencies and how we could push that agenda a little further in the IEPR process, but I think today's discussion and our activities actually point to that direction and the accomplishments that you've accomplished under the DRECP, and the conclusions you've already reached. And that's not to say there isn't difficulties in the transmission, there's still problems. I have Kevin here with me, beside me just in case we get into particular project issues that pop up because they are real issues that pop up in any particular generation project or transmission projects that involve permitting and siting. But that coordination function is actually what has been missing historically, and that coordination not so much between the agencies of permitting a particular problem that you're facing, but the actual policy coordination that takes place as a level of the IEPR process. That's what you want to focus on and that's what you want to give the industry guidance on how to move forward. The day to day problems we're going to have, if our next crisis is the ITC and we're going to have to deal with the ITC problem, your challenge is to try to figure out how you maneuver through that process and deal with the long term challenges facing the State of California while still meeting the needs for today, to either make a decision on a project, or get a project approved.

So with that, I'm probably going to ask you to kind of do a lessons learned: take an example of the project, the Tehachapi project, I think you can find some good instances there, and do a lessons learned, examine what the implications of the planning process is there, the permitting and the implications to see how it could actually be solved in the future. I think it's definitely lacking and it's a good example for you to look at.

So with that, those are the points I wanted to make with you. We look forward to participation in this process and we will continue to actively participate in this process. And any kind of coordination and assistance you can provide at your level is greatly appreciated. Thank you.

COMMISSIONER MCALLISTER: Thank you.

MS. ROSS-LEACH: Hi. My name is Diane Ross-Leach and I'm Director of Environmental Policy for Pacific Gas & Electric Company. So thank you for inviting me to be here today and I appreciate the Commissioners putting this workshop on, it's very valuable.

I wanted to provide a little bit of context about how PG&E meets its RPS obligation, which influences how we're affected by the generation and transmission permitting issues. PG&E relies on competitive procurement processes to meet our year-to-year RPS needs, and this is accomplished primarily through our competitive general RPS solicitation, where we procure approximately 1,000 gigawatt hours each year. And this comes on top of other mechanisms like the renewable auction mechanism or feed-in tariffs.

So that being said, the synchronization of generation of transmission does add uncertainty into this procurement process and, in worse cases, viable projects can be scrapped because a fully permitted project is out of sync with permitting of shared transmission upgrades required for the project to come on line.

I think the developers have done a really good job of providing some very specific examples of how this lack of synchronization works, and I just wanted to provide a bit of an update; I think the Commission asked for where we're at with some of our projects that have been approved by the CAISO for RPS compliance.

The Carrizo-Midway 230 kV reconductoring project is on schedule, it's going to be completed almost, I think, in the next month, I hear. The South Contra Costa reconductoring has been delayed a couple of years to 2017 due to permitting issues. The Borden-Gregg reconductoring project is currently on hold, but it's expected to be completed by 2016. The other projects that are within PG&E's service area, the Warnerville-Bellota, Wilson-Le Grand reconductoring projects have not begun work, but their completion dates seem reasonable at this time.

And then finally, the CAISO is looking at a competitive solicitation for the Gates to Gregg 230 kV line and PG&E plans to submit a bid, and if we're successful, the project will be complete by 2022.

As others have really mentioned, there are really three components to generation project development. There's the project permitting, the Power Purchase Agreement, and the transmission permitting and interconnection process. And this, I'm not going to go into a lot of detail, I think we've heard about that, but I really wanted to focus on the long term planning efforts like we've heard about with the DRECP. That will really streamline transmission and generation permitting and inform the transmission planning process.

I would really like to echo everyone's enjoyment of the presentation by Edison. I think a lot of the experience that Edison described really matches what PG&E's experience has been, and especially the "Challenges to Transmission Planning" slide, I think that's really -- we could put our name on that slide, as well.

We generally support a zoned approach to development and that could really inform and drive future transmission planning. Improvements to the Grid really need to consider this long lead time for development for large infrastructure projects like new transmission lines and power plants. Planning must be done and must be consider the long lead time in the face of uncertainty, while not unduly burdening our customers with the cost of investments that are not needed. PG&E continues to participate in many multi-stakeholder committees such as the DRECP to develop this plan to streamline environmental permitting to expedite solar, wind, and geothermal projects in the Southern California Desert, while minimizing impact to threatened and endangered species. We support this sort of approach, the collaboration and comprehensive planning that would produce similar outcomes that we hope will come from the DRECP, including landscaped level approaches to programmatic permitting, that identifies appropriate mitigation and transmission. And we'd like to see this happen in other areas of the state, as has been echoed.

I think that the DRECP transmission studies that PG&E also participated in on the technical team complement the existing and ongoing transmission planning activities in California. The CAISO and PUC studies generally look out about 10 years into the future. The DRECP transmission analysis looks at a longer term view about transmission needs, which is important for making good decisions about transmission investment in the state. But it could be better coordinated with the approved CPUC transmission portfolios and the policy-driven upgrades in the CAISO's annual transmission planning process so that medium term transmission studies can start to plan for regional transmission needs impacted by implementation of the DRECP.

Conducting similar planning and permitting efforts in other areas of California with high renewable energy potential would be beneficial and help speed the development of additional infrastructure investments where they're needed. The DRECP's transmission study's results, which identifies transmission buildout based on renewable generation scenarios are based on a longer term planning horizon than the existing CAISO studies, and could therefore provide additional insight into the CAISO and other stakeholder processes about transmission needs that go beyond the next 10 to 15 years.

In closing, we really support the DRECP model for planning process, that it attempts to look comprehensively at renewable project development and can inform long term transmission planning. Thank you.

COMMISSIONER MCALLISTER: Thank you very much. Any questions? No, I think we're good. Thank you, Ms. Ross-Leach.

MR. HESTERS: We're going to continue down the agenda, so that brings Tony Braun up next.

MR. BRAUN: Thank you very much. Tony Braun on behalf of the California Municipal Utilities Association. I think I'm going to try to bring maybe a little bit different perspective here today. Most of our members are not actively on the ground as a merchant developer building renewable projects, although we work with them on a daily basis, so I'm not sure where best to speak to some of the day to day challenges of bringing some of these projects home.

I would say that, when we look at this issue and we hear about some of the complaints, our general observations are aligned with what Mr. Richardson indicated, which is heaven and earth has been moved in the last 10 years, let's not lose sight of that fact. And the considerable amount of effort that the PTOs have put in to building out the Grid, the long list of multibillion dollar projects that have been borne by -- the risk of development has been borne by the transmission customers -- is unprecedented in California. And it was that approach to get over the hump, to be able to ensure a financial revenue stream to build these projects out to meet 33%, which caused the multiple filings that Edison made to pave the way to allow them to upfront finance these projects, so a lot has been done and that avenue is still there for renewables that are needed to meet 33%. So that's a sea change and I don't think it would be an accurate picture to lose sight of how much has happened.

From the outside looking in, and with a little bit of education and working on some of these issues as they've come up from neighboring systems -- and no offense to Bob here, but I've seen the matrix on LTPP several times now, and I don't think I understand it yet, and that may be my failing -- but I think unless you implement it, you're never going to be versed in it. And so when we struggle with how we understand what is getting prioritized, and looking at, okay, what is our cost exposure going to be as transmission customers, we're trying to align how the procurement decisions are being made, that seems to be the driving factor, that unless -- and this is our observation as, you know, working for some of the neighboring systems -- unless we can see that a PPA is in place and the generator has that certainty moving forward, everything comes to a screeching halt. And so the sole real takeaway that I'd like to communicate to everyone today is that our observation is that it may not be all about the procurement, but it's mostly about the procurement decisions. And I think that there's also some corollary impacts that come from the procurement decisions that need to be considered as we think about holistic planning.

I stole almost every chart in my presentation, and if you go to Slide 3, for those around the table, I don't know, but you've all seen this, I'm going to tell you this. It comes from Mr. Picker's presentation of all the projects that had been permitted in the last three years. And it's got a county-by-county matrix. And there's why disparity -- and based on what I can tell from talking to people that were part of the head banging to get this to happen is that a lot of it is driven by -- anecdotally, a lot of it is driven by the commitment of the local counties, maybe even personalities that are in the County management, and it has very little to do with some of the big picture things that are happening. It is human interaction that causes Kern to have 8,100 and Riverside to have 2,464, it's not anything related to where there might be other renewable potential.

The other two slides to take in tandem and to drive home the point I think that it's all about procurement, and maybe less about some of the permitting, so of course we've all seen the duck graph -- and we're going to submit all of this for the public in our public comments -- so everyone has seen the ISO duck graph. Munis have a duck graph, as well. And for those that don't have it in front, it's flat. And this is the municipals in the ISO Balancing Authority, and this is probably the only new piece of information in the slide that most haven't seen, this is municipals within the ISO Balancing Authority, this is their trajectory through 2017 to meet their compliance obligations which are the same under statute, and it's their attempt to replicate to almost the Nth detail the ISO's own chart to illustrate the issues that they see with respect to renewable integration. And it's flat. Why is it flat? Well, it's because of the procurement choices that they make. Some of it is historical procurement, some of it is a penchant of using, you know, maybe local landfill gas or something that may be a little more expensive on the front end, some of it I suspect is just a cultural issue with respect to how they view their roles as utilities, and a fear of integration burdens. And so what you get is a much much less reliance on intermittent resources to meet their 33%. And the reason I put that in there is because there's permitting and siting and other consequences to the choices that are made with the significant buildout of intermittent resources. I'm sure the IEPR, we're going to have an integration workshop, but it's going to impact how we build transmission -- what parts of the existing fleet get repowered? What parts get retired? Where do we site new thermal generation? What new products are developed by the ISO and the impact of those on the market?

The procurement decisions drive the transmission development and they also drive a host of other environmental and other factors that are important to achieving the overall goals of the State energy policy.

So I think if I had one takeaway today, it's that we need to really focus on how we're making the procurement decisions, and what the overall impact of those are on the transmission and, in particular, today, consider maybe even moving them up much closer to the front end so the endless dance of the queue and other factors that create uncertainty for developers are minimized and perhaps then we lower our risk of making unneeded environmental intrusions, unneeded transmission development, etc. So I think I'll cease on that note, that one takeaway, is that I think we're not giving adequate consideration right now to both the timing and the comprehensiveness of how we're making the procurement choices that are causing some of the concerns that we're talking about today.

COMMISSIONER MCALLISTER: Thank you for that. I wanted to just quickly -- I mean, it seems like what we're talking about is, okay, people want to procure, but so let's say you make decisions on procurement, but then you're wrestling with this really long -- it then says, "Okay, in order to procure here, then we have to have the XYZ transmission," but the transmission lead times for getting it built are actually so much longer than the generation that there's a -- it's kind of a non sequitur, right? So are you saying that in the CMUA context, or in the municipal utility context, each procurement decision incorporates the transmission issue to the extent that you can comfortably make that procurement process knowing what the additional investments are, and having those penciled?

MR. BRAUN: Answer a qualified yes to that. I think there's a much greater sensitivity to maybe building something closer to home. There's a much greater sensitivity to building utilizing transmission that already has excess capacity. It's a much more integrated approach going forward, I want to call it "old world" or "old school" where it's, you know, there's greater commitment of up front capital, farther out from the commercial operation date of the projects. Part of this is I think we run into in the RPS context, right, where an issue comes up and that's to be expected, it's a very evolving field, and you have several municipal communities that come in and say, "We've already spent lots of money pursuing that commercial development, you're changing the rules." Well, that's because it could already be that we've already committed significant upfront funding and we can do that based on sort of older vertical integrated, more traditional, vertically integrated model, committed upfront funding to that. We may have even put in financing structures where we're going to pre-pay for the output of the projects. There's a lot of tools that are being brought to the table that aren't within this disaggregated development model.

COMMISSIONER MCALLISTER: Yeah, so I guess I would just point out the representatives from L.A. County actually had some similar points and I think a lot of this is sort of a local government issue with predictability, want sort of a sense for what's going to happen, so we can inform our citizens and, in your case, you know, governing boards, etc. So I do think we have -- I mean, it is obviously a very different context, but we do have state policy we're trying to input, we have large -- it is a little bit Mars and Venus here with respect to the broader State policy and then sort of how it trickles down to a local authority, but I certainly -- I think that's a model that kind of should definitely be in the mix and at the table in these discussions. I think it would be helpful to have that kind of bottom up appreciation in an integral way of -- you know, if the pieces are getting moved around on the chess board, you get to bring it home to how things happen sort of at the local level, and I appreciate your perspective on that. So, thank you.

MR. STRAUSS: Hi. I'm Robert Strauss with the Public Utilities Commission. I just wanted to make a couple of comments. So taking off where Tony left off, one point that he made was that the ISO's duck graph, and what that means is the potential need for flexible resources to deal with potential over-generation by solar in certain months of the year, a lot of months of the year, and the need to replace that solar when the sun goes down and the load hasn't gone down. And that's a major reliability need. And keep in mind, I mean, my assignment is to plan for a reliability energy system that takes into account the State's environmental goals and does that at the least possible -- least reasonable cost. And so just the concept of, you know, we've been talking here about how can we get transmission lines to this area to get more solar? That's not my mandate. My mandate is to meet the environmental goals of the State, and maintain reliability for the least possible cost. And current research -- and we are spending a lot of money -- a lot of research time, a lot of resources, on looking into the flexibility of resources to the system this year. And the ISO has devoted a lot of resources, and that's the main focus of the LTPP which we've talked about this morning, on Track 2 this year is looking at flexibility. There's been studies out that talk about the declining value of solar with increased penetration.

So when you talk about synchronizing generation and transmission planning, you need to talk about more than just where do I build the transmission line to build the generation of the current resource of the day, but to synchronize the whole system. And we're working on that, but it's a very complex problem. And you need to think about what's needed to keep the system reliable and at what cost. And we're trying to work on that and I can't say that we've solved all the problems and, you know, Edison was just talking about the transmission lines that they're building to meet the 33% renewables, that the ISO has told us that if those lines get built, we'll be able to meet 33%, but we're going to have flexibility problems with that. And going beyond that to a further penetration of different types of renewables, we need to study more before we commit to it. So to, say, go out there and build a new transmission line today, to access new renewables in an area without fully studying what the impact of those renewables will be, and will be able to use them, is a major concern to me because that's what I've been tasked to do.

We have been working on a lot of levels to improve the synchronization between transmission and generation planning. We've been doing it for years, trying to get the shared assumptions. When I started working on this, the ISO had its demand forecasts, the CEC had the IEPR demand forecasts, and the utilities had their own individual demand forecasts, you know, we're now all using the IEPR demand forecasts. I mean, that may sound like a simple decision, but it took years of negotiation to get to. There are other similar assumptions that we're working on and getting much closer to. I mean, to me that's a major part of synchronizing the transmission and generation planning, is getting the shared assumptions for the analysis, and to considering as many of the complicating factors as possible, and building new models to be able to take into account the complicating factors as they come up. So I don't have the grand solutions. I mean, we've been working on this for years and the problem gets more complex the more we work on it. But we are working on it.

COMMISSIONER DOUGLAS: So, I just have a couple questions based on that. I think that was helpful. I think that you are raising important issues when you talk about the fact that, as we think about beyond 33%, and we think about renewables, we do need to think about the mix and integration and how do we come to a system that is as functional and high value as possible, while also meeting longer term renewables goals. And I tend to agree with the starting point being, you know, let's do some analysis, let's make sure we have some shared assumptions starting with the demand forecast, but beyond that as well. I guess I wanted to ask where, in terms of the PUC work, is any of that analysis occurring? Or is this just at the very beginnings that you're articulating a need and we need to go from there?

MR. STRAUSS: We've been working for the last couple years on the flexibility analysis and working with the ISO. As part of the LTPP, the ISO has done studies, Edison has done studies, PG&E is working on it, I mean, we've been working with the parties to develop analysis where we've got hearings and testimony that is anticipated to occur this year, but the decision towards the end of the year or early 2014 on identifying flexibility needs on the projected portfolios --

COMMISSIONER DOUGLAS: I'm sorry, is that analysis focused on 33%?

MR. STRAUSS: Yes, 33%.

COMMISSIONER DOUGLAS: Okay.

MR. STRAUSS: To the extent that we have the -- I mean, these studies take time to do. To the extent that there are resources available to do them, one of the portfolios, one of the scenarios that we talked about this morning, was the 40% scenario. We also need to keep in mind that the State's policy, besides being at 33% renewables, is also pushing towards distributed generation, towards load not requiring new transmission, and that also impacts -- and we're studying that also and ways to get there. Part of that deals with the interconnection work and we've got proceedings going, we've had major improvements on the distribution level interconnection, there's a long way to go, there's a lot of different pieces that need to be addressed on that. You heard the presentation this morning about what the ISO has been doing on their transmission level interconnection, and we've participated in that. This is an ISO thing, they've done the majority of the heavy lifting with a lot of parties to try to address that issue.

COMMISSIONER DOUGLAS: So can I ask, that's a very thorough response and that's helpful. I guess I have two follow-up questions on that. You know, one is it's well and good, and no doubt helpful, and very important to do this analysis around 33%, but I'm struggling to get my head around the relevance and timeliness in the context of where utilities are with procurement, which is that they have essentially procured most of what's needed for the 33%, speaking of the IOUs right now --

MR. STRAUSS: Uh-huh.

COMMISSIONER DOUGLAS: -- and so it's very helpful to do this analysis, but the IOUs have got the portfolios, they've got to a large degree, I mean, there will be no doubt some outer year procurement that's needed around 33%. I guess the other question I have is that this is the sort of issue that can sometimes be analyzed forever, and yet it's a fast moving policy environment that doesn't allow analyzing anything forever. And I wonder if there's some no regrets conclusions that can be reached sooner rather than later, such as placing a higher value on attributes like storage, or renewables that can be more easily integrated, you know, rather than integrated with more difficulty the value of potentially hybrid projects that have a longer operating profile, you know, it seems to me that even before many of the very detailed analyses around 33% are done, it should be much simpler to come up with some directional recommendations that the State can act on, you know, speaking more broadly through the Energy Commission, through the PUC, through the ISO, that can make the problem less and not more, and that can provide a market signal and a policy signal so that we are procuring, you know, a balanced mix as we meet our renewables goals. And so I'm curious your thoughts on both of those questions.

MR. STRAUSS: Well, we clearly aren't standing still. I mean, I talked this morning about the authorizations, the several thousand megawatts I got authorized this spring, or this winter, I should say. Part of that authorization was to replace the OTC plants, but it's also being authorized, and part of it is renewable and part of it is storage, and part of it is natural gas for the flexible natural gas with the intention of killing two birds with one stone, doing no regrets going forward. The Commission has authorized and approved various of these projects, the transmission projects, to meet 33% on a no regrets basis. I mean, the analysis that we're doing this year, we're hoping to come up with decisions at the end of the year of whether we need to buy more flexible resources to make sure that the system is stable and reliable when the 32% renewables come on line. And so by 2020, 2022, we can have things in place in it. And we've timed it so that we can build something in that time and get it on line in that period, you know, hopefully depending -- but there's a lot of variables. So, I mean, we're constantly moving forward. We aren't standing still and not authorizing anything, we're not building anything, we're constantly evaluating and trying to do no regrets decision making. And when I say "we," I mean the five Commissioners, the decision making body that I work for.

COMMISSIONER DOUGLAS: Okay, thank you.

COMMISSIONER MCALLISTER: Thanks very much. That was good.

MR. HESTERS: We're on to you, Neil.

MR. MILLAR: Thank you. I would like to tag on to some of the comments coming both from Tony and from Robert about the not losing sight of the progress that's been made to date. You know, we are talking about a current queue that's now back comfortably over the all-time peak ISO demand in terms of the amount of generation that wants to connect. So if the perception is that the IOUs are done getting to 33%, there's considerable generation that hasn't heard that yet because there's still a lot of interest in getting connected prior to 2020, so the competition is still out there. So that's one of the areas of focus that we have to pay attention to.

We haven't seen the need for additional mega transmission projects to get large amounts of renewables to load to meet 33%. The last two transmission plans, or the most recent transmission plan identified some smaller projects addressing more localized issues, rather than the kind of project of a Tehachapi, or Palo Verde Devers type projects, so much more contained projects, definitely needing to make sure that we continue to move forward to take care of the reinforcements that are necessary.

So in this discussion, I feel like I keep looking up at the wrong time as we move back and forth between the discussion of is additional transmission needed to get to 2020 and the 33% RPS, and what's beyond 2020 as we start to look forward to that, especially with the additional uncertainty of besides what's beyond 2020, how will we get there? There are so many other additional uncertainties, I was thinking if we were only limited to the uncertainties that I heard about so far, that would be lucky. With the additional uncertainty around the distributed generation that came up, the future of energy storage, the increased focus on energy efficiency and demand response programs to obviate the need for additional transmission reinforcement, and that's something that the ISO is determined to work through with stakeholders, to ensure that long term 40-year assets aren't being built that aren't needed. The least regrets process is very important to us because this is Ratepayer money we're committing to for a very long time. So we do need the due diligence around that.

In terms of the getting to 2020, I do agree with Robert that there's been a lot of progress made. The analysis necessary to get to the variable or the flexible generation requirements, to have a better understanding of what that actually means, is really a major shift. I hate to use the word, but it is a paradigm shift for utilities moving from conventional load patterns and conventional resources to this kind of analysis. We do think that with the work that's going on now, we're better positioned to come to better terms around the transmission implications of what the flexible generation requirements will be driving, but the ways in which we actually produce that flexibility still has a huge amount of uncertainty to it. So I do agree with Tony that the big concern here, or the big question will be, how are these resources actually procured? What makes up that resource pool?

On the flip side, I do think that the level of coordination we've seen, and I'll point to the portfolio development process as a way to get some sense out of the chaos of all of the generation interconnections was a giant step forward; that doesn't get us all the way to all of the future challenges, but it was certainly a huge step in the right direction. And that really has been the basis for how we've been seeing how we will get to the 2020. We have transmission that hopefully continues in flight. We have also been concerned with what we've seen as delays for some of the major transmission projects. Some of the projects that are still on the books now had in-service dates as much as a decade earlier than their currently scheduled for. That's obviously a concern, and the level of uncertainty that can create for generation development I don't think we can set aside. It's very -- it's uncomfortably easy to trivialize the challenges that generation developers have in front of them to finance projects, move forward on all of the facets of a contract, interconnection, all of the permitting requirements, to just point to one issue as being the one issue that needs to be taken care of to make the problem go away.

We are working on managing the generator interconnection obligations. As the generation that has developed, or sought interconnection under previous tariffs moves forward, there are obligations that generators have, there are also previous tariffs that are still in effect for some of those earlier generators where the generation simply doesn't have the obligation attached that some of the generators today, the more recent applications do. We are working through the process and committed to working through those processes with the generation development community, but these are very thorny issues. They involve legal rights; people have invested a great deal of money in developing some of these projects, and they don't want away gently if they believe that their project has possibilities in the future.

So there are some real challenges there. I think the industry has been overall making some great progress considering the sheer enormity of the fleet transformation, of moving from conventional resources to a 33% and starting to consider what happens beyond 33% RPS, that I don't think we should lose track of.

I should also mention, though, we are here specifically to hear both what can we contribute and also what can we learn to help improve our processes and to inform our conversations as we move forward in trying to coordinate more action going forward. I'll stop there for now. But thank you.

COMMISSIONER MCALLISTER: Thanks very much.

MR. HESTERS: Ali, you're up next.

MR. AMIRALI: Mr. Chairman, Commissioners, thank you very much for giving me the opportunity and thank you for the CEC staff for organizing this forum and allowing me to participate in this.

I represent Startrans IO which is a participating transmission owner with CAISO. We are a subsidiary of Starwood Energy Group Global, which is a private equity company that specializes in investment in energy infrastructure projects.

Now, Mr. Desmond and Ms. Robin so eloquently pointed out all of the issues that are being faced by the generation interconnection community. And one of the advantages of going -- being one before the last is I get to pick on everybody's comments and say "me too." So I am going to take thorough advantage of that and, you know, reflect back on some of the things that have already been said.

One of the things that you have heard, one of the main concerns in generation development that the developers are facing, both renewable as well as conventional generation right now, is the disconnect between the timing of the development of a transmission and generation project, long transmission project, long term transmission projects have a quite longer lead time and based upon some of the numbers we have heard anywhere from 84 to 104 months from the time you put pencil to paper, is the lead time for doing even a marginal project in California.

There has been -- our friends at CPUC indicated the need for -- the system needs changing, where there is a need for more flexible generation. CAISO is faced with issues and challenges associated with intermittency of the resources in maintaining reliability while satisfying the state's needs. And while doing that, they are looking for no regret and low regret projects and actions that will accomplish the state's goal and help them maintain their charter, as well.

So the question I ask is what is a low regret and no regret solution. The way I describe a no regret project is something that has got low cost, is both environmentally friendly and has low execution risks, and it satisfies all the needs of the system and the State's policies. Now, to that effect, on looking at and making those opportunities available, I am going to commend ISO's efforts into implementing the existing transmission planning process and doing their best to align that with the generation interconnection process. I think this has gone a long ways towards solving some of the inconsistencies that we were seeing. Also, it has allowed other participants, in addition to the existing IOUs, to come in and propose projects such like ourselves, even though we are a PTO, we are not an IOU with the ISO. But it allows for opportunities to provide more creative solutions and more opportunities for proposing projects that satisfy the needs and that are low regret scenarios. I'll give you one example. So we are a part owner of the Mead Phoenix and Mead Adelanto projects, they are two 500 kV transmission projects that connect Central Arizona to Southern California via Southern Nevada. Now, we are as a part owner of the project working with existing owners of the project, and have kept ISO informed of this, we are working at converting this project from its existing AC operation to HVDC operation. Now, this is an opportunity to take advantage of the existing unutilized capacity on existing conductors and to bring new generation in from a generation rich region into the heart of the load center.

Just a couple of features of this project. First of all, the existing project is a 202 mile transmission line, it does not need to be touched, nothing needs to be done to the existing project because the builders of the project, which are the municipal utilities of Southern California, they had the foresight to build a project with HV design, build, and permit the project with HVDC standards, so the project is already ready to be converted into HVDC. It has got a low environmental footprint because all you need is 40-acre converter stations, 40 acres for converter stations on both sides, and 13 miles of new transmission line for maintaining reliability and integrating the existing generation into the system. It has the lowest dollar per megawatt capacity increase cost of any project that you will ever see in Southern California in a major project. Very short development cycle. Actually, the development cycle for this project is almost as short as most generation projects. You can put it in execution -- you can produce COD in 2017. Another advantage: it takes care of the flexibility issues because, being HVDC, the intermittency goes away and now you have got 2,200 megawatts of additional capacity that the project can bring into Southern California -- and that is all controllable generation now, it does not need to be fixed -- the intermittency issue does not need to be addressed with that.

So what it has allowed is the opportunity for creative solutions to be put forward. Now, ISO has done their part and, in order to assist the ISO in determining what kind of a policy driven and/or creative projects that can be brought in for sustainable inclusion into the transmission planning process, it seems appropriate to hear from other agencies, as well. And do that extent, we have a request of CEC. We would like to respectfully suggest that CEC assess the value of the projects like map up grid -- or it's called Mead Upgrade Phase I, conversion of map into HVDC. And in meeting the State's energy policy goals and develop means to submit these projects into the CAISO, we would like the CEC to help CAISO in defining the policy projects and getting ahead of the curve, so, as Neil indicated, what do we do after 2020? Well, there are projects that are no regret projects and are satisfying the needs of the system. We would like the leadership at CEC to help ISO move that process forward.

COMMISSIONER MCALLISTER: Thanks very much for that. And if ISO wants to sort of comment on what our existing sort of blending infrastructure between the two agencies, how that might apply, then that would be helpful to hear. I'm lead on the IEPR, but not necessarily on this particular, so I think really this is an area that's through the IEPR staff, Suzanne and Lynette, we can circle back with the relevant staff and Commissioners on that.

MR. HESTERS: And now Carl is up.

MR. ZICHELLA: Yeah, thanks. I got warmed up. God, what a reputation I have. Good afternoon, everybody. I want to emphasize a few things. I'm not going to try to repeat things, but I think some general themes have leaped out here today that coincide with what NRDC has been promoting in terms of ways to address this very problem, the first of which had been mentioned: I think Joe Desmond talked about the differences between timing and constructing generation and transmission, and that's a real problem everywhere, you know, between three to five years for projects, seven to 10 years for transmission. One of the key things that's been identified and worked on in this state to help address that is the coordination between the agencies that are addressing permitting in its various venues, to try to be much more coordinated between the State and Federal Government, and between the State agencies. That's really benefitted from having a policy driver, someone in the Governor's Office and in the Secretary's Office, that's Secretary of the Interior, to sort of move those things forward and make sure that people fill their commitments. Those are lessons learned, they have worked and are working, and they're being emulated elsewhere in the country because they have worked. Memorandums of Understanding similar to ones we've operated on are underway in Nevada, for example, a close partner of ours. So that level of coordination is extremely important, it has worked, we need to continue to move forward with it.

I think Kevin Richardson very amusingly

addressed a real problem, and that is we're planning the system around individual projects in the queue of individual projects, instead of system needs. It makes it very difficult to do big picture thinking of the kind we've just heard about when you're trying to just figure out individual project needs, and which ones are viable because they may or may not have a PPA. While I don't want to discount the importance of sort of winnowing the weed from the chaff in these projects that are in the queue -- as Neil pointed out, there are legal rights that people have -- I do think we can't be hostage to that either. We have to look at things that expand the effectiveness to the system in terms of reliability, but also which reduce the integration costs we face, make it easier for us to meet other State goals like developing projects on impaired lands, as Bob Dowd talked about.

Now, Bob Dowds and his group have done something really remarkable, they've taken the zone process, they've applied master planning to that process to phase in a very large solar development -- with transmission included. He mentioned that, I didn't want to skip over it because I think it's very critical that generation and transmission be considered together.

You know, Diane talked about the zone concept, and this is one of the things that makes the zone concept work. One of the main benefits of doing zoning for renewable energy resources, not only reducing the environmental conflicts, not only to identify good resource areas, but to rationalize the transmission that you need for it. So I strongly agree with what Diane said. This leads us, if we're able to do that, it leads us to be able to do what I call right-sizing, what many people refer to as right-sizing lines, is planning for present and future needs as we did in Tehachapi, as the Westlands project contemplates doing for transmission solutions for their phased development over a decade to try to bring that project to a rational reality, a very reasonably planned process, it'll bring us to a better result.

I have to say, I am pleased with the greater coordination that we're seeing between the Energy Commission, CAISO, and the CPUC, but because we do this hand to baton type of planning, I think we often back ourselves into decisions and make judgments that don't really maintain the big picture when it comes to system needs, as well. I want to really congratulate CAISO in taking a step away from that, in particular with the Gregg Two Gates proposal in the Central Valley, where they listened to stakeholders about this very thing and proposed prioritizing that line because of additional policy or economic developments in addition to its reliability benefits, and one of those is access to the largest pump storage facility in California, our only major energy storage facility that we have. And the studies that they've run and shown, that this transmission improvement would greatly increase the availability of that resource for regulation and load following services. Extremely important, it's not something that comes out of a queue driven approach to this; in fact, that would frustrate and prevent it from occurring. We need to sort of step away from that very constrained view of how to develop transmission and maintain it.

I think it also leads you to this whole approach, getting the most out of the existing infrastructure. I have heard over and over again, and I'm hearing much more frequently from developers and from municipal utilities and others, this HVDC switch, the idea to increase capacity, it enables you to use much of your existing infrastructure and. where you may need a new right of way, a smaller right of way. It gives you a chance to have less delays related to environmental and cultural resource conflicts and it preserves the utility of existing rights of way, which are so precious in California -- just ask LADWP who cannot find one -- this is a very important issue.

When you get a things like congestion, reliability, access to energy storage, and other state benefits that maybe not are within classically the transmission planning realm such as economic development in really depressed parts of the state, and opening up areas of disturbed lands to development when they would not be prioritized because they couldn't be in the discounted core of portfolios that are handed from the PUC to the Energy Commission because of the PPA issue. And if you had an orderly development plan like they have at the Westlands Water District, Westlands Solar Park, that whole project could sink because of the way we're prioritizing the transmission development, it's a very important area, the transmission benefits the entire state, and the generation that would come there would give us additional geographic diversity to the resources that we already have.

I think another thing that has not come up, but I think we can't ignore, is the opportunity to do more consolidation of Balancing Areas in California and coordination between balancing and/or coordination between Balancing Areas and IOUs and POUs. The extent that we can share transmission resources, take advantage of increased capacity from the improvements, and finance projects that are spread over many more Ratepayers that would definitely benefit, reduces costs for everyone. So I think that is an area where we're leaving a lot of opportunity on the table, although we're spending more than we need to, we're duplicating infrastructure, and it's unnecessary.

COMMISSIONER MCALLISTER: Let me ask just real quick, are there examples of those co-investments between say, Investor-Owned Utilities and POUs on transmission?

MR. ZICHELLA: Yeah, I think there are. Right now, San Diego Gas & Electric has a Memorandum of Understanding with IID, they're planning and building transmission upgrades together. IID has a similar MOU with a fellow POU, LADWP, on transmission. There are conversations going that I can't get into right now, possibly about additional dynamic connections and shared transmission between Southern California Edison, San Diego Gas & Electric, and DWP. A lot of this is around looking at the reliability supply and services problem related to the SONGS outages, and perhaps prolonged SONGS outages in Southern California. None of that is very advanced, Mr. McAllister, but people are recognizing that if you cannot address your congestion issues because you don't have the rate base for it, and your neighbors could benefit from the same transmission, it really behooves everybody to try to work together. And CAISO has indicated a real willingness and an interest in participating in that, not necessarily insisting on control which some of the POUs would really find objectionable. I mean, we're getting to a point where this becomes much more real, it solves reliability problems for us in a much more holistic way, it saves Ratepayers money, reduces the environmental footprint in transmission, and even improves our ability import geographically diverse resources from out-of-state.

Finally, I think given that we've talked a lot about how we have worked very hard for a very long time to coordinate the efforts of our various State institutions, we have had an laughed about in previous workshops the sort of disconnects between the timing and mission that these entities have. I think it's time, and NRDC has previously recommended to Little Hoover Commission and others, that we consider a State transmission authority that would combine the agencies together into a single one-stop-shop. The states that have been going in this direction have been able to address transmission much more consistently, can look at the bigger picture needs of the system, the Eastern RTOs are able to do this, for example. So I just think that it has been recommended before, I will recommend it again, I know it's a difficult political lift, but I think to the extent that we could rationalize the way that we plan transmission, not make people go through hoops at three separate entities, three separate proceedings, to do that stuff in a more coordinated way, hand off the results for cost recovery through the regular PUC process, I think we could probably do transmission with a lot less delay, a lot more certainty, a lot more confidence that the judgments we're making in the transmission investments we are supporting are going to do what we hope they would do, expect they would do, and support the renewable transmission we're trying to make. Thank you.

COMMISSIONER MCALLISTER: Thanks very much, Carl, very helpful. I have by far the longest list of bulleted recommendations that I have on my page here, so thank you.

MR. ZICHELLA: I benefitted from going last.

COMMISSIONER MCALLISTER: Any questions? So I guess at this point we move on to public comment?

MS. KOROSEC: Yes. All right, I've got four cards here. First is Jeff Gates from Duke American Transmission Company.

MR. GATES: Hi. As she said, my name is Jeff Gates. I'm with Duke American Transmission Company and we are developing the Zephyr Transmission Project which was talked about this morning in conjunction with the Pathfinder Wind Project. Thank you for inviting us to attend and address this session, we really appreciate actually this topic being added to the IEPR Workshop and being able to address both the morning topic of out-of-state costs, as well as the issues with generation and transmission planning. I'll say three main points, I'll try to take less than a minute on each so I stay in my three-minute limit.

First, we're very appreciative and are encouraged by the coordination between the three main bodies in California, the CAISO, the CPUC, and the CEC. But even with the coordination, we see that there's a couple of holes where no one body has the jurisdiction; and somebody mentioned before we have this pass the baton off in the transmission planning process and, in particular, there's one place where that baton gets dropped.

If we think about transmission planning, the way that the ISO does their plan, they take the California -- the CPUC renewable portfolio that the CPUC develops, and they look at the transmission needed to meet that portfolio. So you have future hypothetical generation, it's not there yet, but there's a hypothetical portfolio that's given to them, and they can study the transmission needed for that. Conversely, if you have existing generation out-of-state that may be low cost generation, but it can't get into the state because of a congestion issue, you can ask for an economic study request and they can study that situation where you're accessing existing low cost out-of-state generation and bringing that in-state. Where there's a hole is, do you have a hypothetical or a future out-of-state generation that is low cost and there's no existing congestion on the system because that generation doesn't exist yet? So we have asked for the past two years to be studied, an economic study request for the Zephyr project in the CAISO planning process, and have been kicked off both times and saying, "You don't fit in either criteria that we are allowed to follow to study transmission planning. You have to either be identifying a specific congestion relief, or you have to be in the CPUC official portfolio bucket." And so in this past study, the ISO did do a sensitivity case for high out-of-state Wyoming wind, and we appreciate that very much, but they were not allowed to go to the next step and do a full economic study request on that.

A corollary to that, and this goes to the transmission generation timeline lag a little bit, the total cost of energy is what matters to the consumer at the end of the day, it's not the cost of transmission and the cost of generation. And if you look at the typical bill, the cost of transmission is a very very small part of that, so what matters to the consumer is the lowest total cost of energy. And this leads to what may be a counter-intuitive result, which is that spending more on transmission may lead to a lower total bill and, conversely, minimizing transmission spend, which seems to be sort of objective function of what a lot of the planning that's being done now is, may lead to a higher overall total cost. And the Zephyr project is a very good example of that. WECC has studied this and they have shown somewhere between $600 million and $1.5 billion in annual savings to California consumers from accessing the wind in Wyoming because the resource is world class there, and even with the high cost of building an 850-mile transmission line, the total cost of energy and savings to the consumer in California is still substantial. And as was mentioned this morning, there's an additional $100 million in benefit from looking at Wyoming wind and the diversity that that brings to the system vs. building everything within the state. So there's quite a bit of savings, but there's not a good way to build that and under the current processes, there's not a mechanism to look at that generation that's out-of-state and officially get that economic study and those benefits quantified to make an informed decision.

And then the last thing I want to say, and Neil brought this up, is that the only thing that seems certain here is that there's uncertainty. And we don't know what the cost of future generation types is going to be a decade from now, we don't know where projects are going to be, so it seems to be that the best thing to do is to plan for a robust flexible system that will meet many future possible generation outcomes and, given that there is such a discrepancy between the lead time and developing a transmission project or versus a generation project, is start planning for the transmission now, plan for more than you might need because it's much easier to scale back and not build it, even if you've planned for it, than it is to try to catch up and say, "Oh, now we need to do a transmission line to go access that generation," and it takes us another decade to get there. So if we plan for it now, we should have a much better outcome and we can scale back much easier later on at fairly low cost. Thank you again for your time.

COMMISSIONER MCALLISTER: Thank you.

MS. KOROSEC: Next, we have Jesus Arredondo from Wyoming Infrastructure Authority.

MR. ARREDONDO: Mr. Chair, Commissioners, thank you for the time. I have -- I could get crazy on the IEPR too, not as much as you, but I had a 20-page presentation that I'm going to skip because I know you guys have to catch planes, so --

COMMISSIONER MCALLISTER: If you do want to put that in the record --

MR. ARREDONDO: I will. I will submit it to the record, Commissioner. The Wyoming Infrastructure Authority -- well, let me back up -- Jesus Arredondo, again. I'm representing the Wyoming Infrastructure Authority today, but I am a consultant and you see me on other issues at the Commission.

Today I want to talk a little bit about what Wyoming is doing. Why in the world would Wyoming care to present anything? You just heard why, because we have a tremendous amount of wind generation that is world class. And more importantly, it's coincident wind to California. Wyoming's wind goes nuts and California's wind totally falls off. And so we could actually shape wind on wind. That's something that we have not really talked about in California. While we're tackling the aspect and the challenges of how are we going to integrate all of this renewable generation, one thing that's absent is a discussion on renewable on renewables, and how we might be able to shape that.

The Wyoming Infrastructure Authority as an instrumentality of the State of Wyoming created through statute with appointments to a Board by the Governor, Governor Mead, had a great idea: let's promote what we can outsource -- wind, wind generation. The rest of the West is looking for renewables, we've got it, we can't use it all, so we'll look to see if we can build transmission and we'll promote it to other parts of the West. And that's exactly what's happening. And we started to tour in California back in -- I want to say in October-November of last year -- and we've been going around the state talking to all the regulators, we've talked to the PUC, we've come to the CEC, we've been to the Legislature, and we're going to continue to make rounds to help educate people. We got a study that was produced by the University of Wyoming that shows these coincident wind factors and how we could actually work to shape this wind, and by the way the transmission would be delivered to a Bucket 1 resource under the RPS, so it's perfectly suitable for what California could use, and what the IOUs might be able to use. I know that they're at 33%, but they're at 33% and we haven't talked about how they're going to shape that when the intermittency kicks in. That's something that maybe they have already thought about, I just haven't read about that publicly yet.

So again, Wyoming is promoting quite a bit of generation. Also, in addition to the transmission, about 6,000 megawatts of generation can come from wind. We have had conversations already with PG&E and we look forward to talking to our friends at Edison and SDG&E, as well about this.

Just, again, I want to cut to the chase, shaping renewables on renewables, let's think about that. That is something that should, for crazy people like me, get us excited because we've taken on quite a challenge in California, and as a Californian, I'd like to say, you know, I like natural gas generation because that's going to help us make that blue bridge to the green future, but at some point we do want to get to our goals, we want to get beyond 33% as the Governor has said, and there are ways around it, there are ways to do it, but it's going to be a hard road to get there, but we can depend on the rest of the West like we have been our entire history. Never have we produced the generation that we need to keep our lights on in California, let's lean on the rest of the West for some of those renewables, as well.
Commissioners, thank you. I will submit this to the record, and I'm happy to take any questions if you have them. Thank you very much.

COMMISSIONER MCALLISTER: Great. Thank you.

MS. KOROSEC: All right, last we have David Smith from Power Company of Wyoming.

MR. SMITH: Thank you. I don't think we planned to have the Wyoming contingency here, three in a row, but it's hard to get a seat at the dais, I guess. Again, my name is David Smith. This afternoon, I'm representing Transwest Express, which is an interregional transmission project. There were some questions up about some of the challenges in synchronizing the transmission process and the generation process. There's some just general fundamentals about the two different types of projects. Again, they have different asset lives, we talked about a 40-year asset life for transmission, generation might have a 20-year asset life, so you've got to think of the next generation, the next tranche of generation that will come on in these transmission lines, when we think about investing in transmission.

The other element is, generally transmission line does take longer to permit, it goes through a lot of different places, lots of different jurisdictions, and everything else. I think the experience that California has been, that it's taken a lot longer, that my experience in the West is it's taken a lot longer, and everywhere it takes longer. There probably are things that you can do to speed that up, but I'm not sure that you would be doing the NEPA process, or whatever environmental process that a lot of folks count on to make sure that transmission lines get put in right, you know, has been done correctly.

There's been some question about philosophical questions and what comes first, chickens or eggs and stuff like that. The important thing here is both the chickens and the eggs have to show up at the same time. You have to have the transmission and the generation at the same time; if you're going to cook a dish with chicken and eggs, you start the chicken long before you started the eggs. That's true with transmission and it's generally been true forever about transmission and generation. Tony talked about different paradigms that are used to rationalize these capital decisions, there's lots of different IRPs and other things that traditionally were applied in vertical utilities and have been applied throughout the country and the world, by reformed markets, as well. What I see in California here with this procurement, first, generation interconnection process is kind of a hybrid that kind of came, I think, out of building gas generation close to load. You interconnect it, you connect quickly, you get the gas line, everything kind of worked pretty well for that process with the open access tariff. You're really stretching it when you start to get remote locations where renewable resources are going to have to be.

I think I've heard from the different utilities that Tehachapi and other projects where transmission led first was a very good process. What I wanted to say is there are opportunities out there, we've heard about another project, TransWest is a 3,000 megawatt transmission line from Wyoming to the California markets that would provide low cost resources. We're not looking for help in permitting, we're already permitting the project, we've talked about that this morning on transmission lines and distribution, what we're looking for is this analysis about how these would be incorporated into a system, and does it make sense to incorporate those in the system? I think that Jeff spoke about some of the requests that he's made; we've made similar requests for analysis to be done by whatever body in California is responsible for transmission planning, or the groups that are responsible for that, and have found that it's been difficult to have a project that is moving forward, doesn't have PPAs, is putting effort forward without a commercial guarantee from anyone, that if it's fully developed it will be taken off. So we're at-risk developers, truly at-risk developers, without any funding source from customers or anyone else for this advancement. And what we're asking for is to have a consideration about how this could fit into the broader world, broader plan.

We think it would be very important for California's future to have some contingency plans, some flexibility -- we talked about flexibility in the operating sense, but with this one set of plans, if any of those fall, I'm not sure what happens to the 33% goals, and that's a large regret that I think has to be considered by everyone. So, thank you. We'll submit comments, as well.

COMMISSIONER MCALLISTER: Okay, thank you very much.

MS. KOROSEC: All right, is there anyone else in the room who would like to make a comment? All right, we're going to open the phone lines for a moment here and just see if we have anybody on the line that wants to make a comment. All right, the lines are open if anyone would like to make a comment or ask a question? All right, hearing none, I think we're good to go. Thank you.

COMMISSIONER MCALLISTER: Great. Well, thank you very much. We're just past our agenda, but I have to commend the staff for keeping us really on track, we haven't floated around too much, and I know they know me now -- I've been here a year -- they know me that that would happen if they don't do it.

So I really appreciate everybody coming, this was another fabulous panel, obviously a lot of expertise in the room, a lot of brain power, and a lot of real hard core project experience, and from all the different perspectives, so I really appreciate all of you coming.

And this obviously is a living breathing discussion. I think several key points have emerged here, at least for me, maybe some of the other Commissioners and others were aware of this in some detail, but I do believe several of the issues here we have to push them forward and really try to streamline this process and figure out what makes sense for the upper level kind of long term what's best for California kind of an approach for transmission planning, and sort of get out from under the chicken or the egg, you know, on the one hand we have a lot of mouths to feed, but we can decide what we're going to eat, right? So I really appreciate it, again, and thanks. And we stand adjourned.

(Thereupon, the Workshop was adjourned at 4:53 p.m.)

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